APPENDIX C

APPENDIX C INDEX

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1.2	Gen-Eq	General Equations
1.3	NHV_{cz} and NHV_{dil}	Calculating NHV_{cz} and NHV_{dil}
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1.6	Tip-Area-Eq	Calculating the Unobstructed Cross Sectional Area of Various Types of Flare Tips
1.7	G-Drwg	Depiction of Gases Associated with Steam-Assisted Flares
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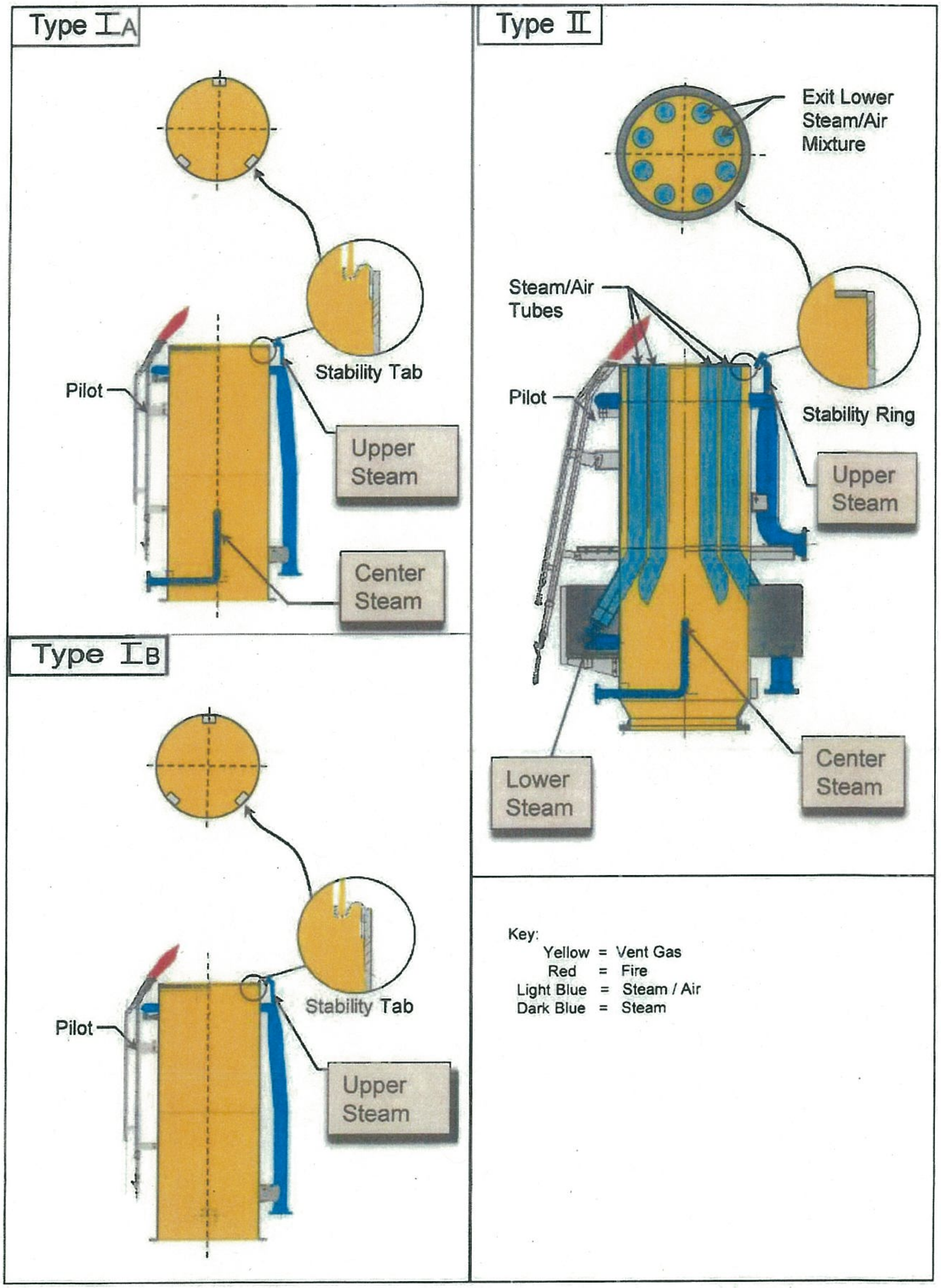
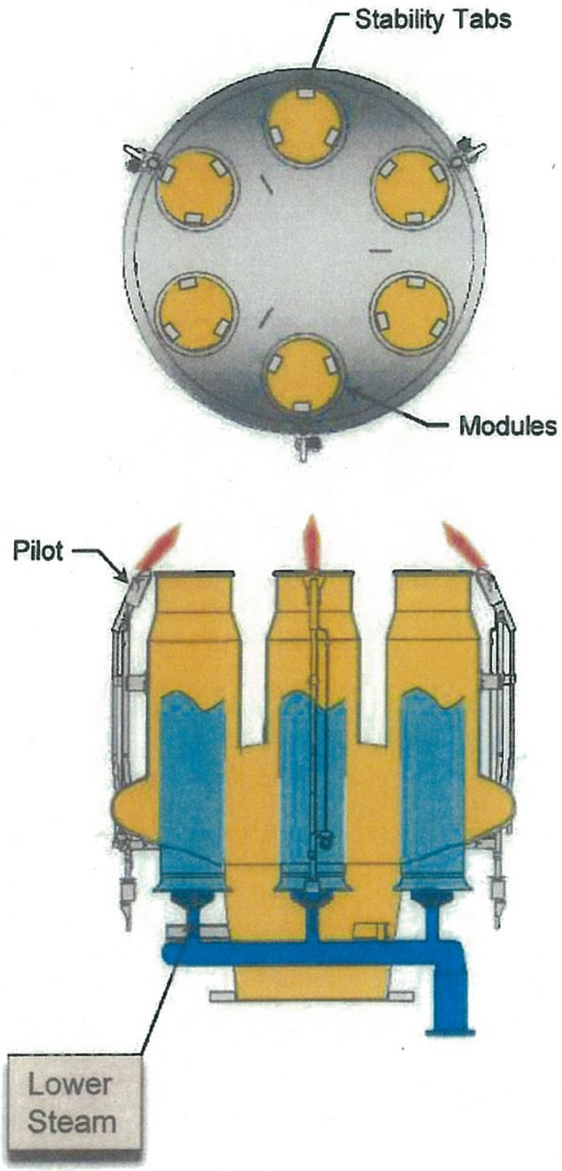
APPENDIX C-1.1

Appendix 1.1

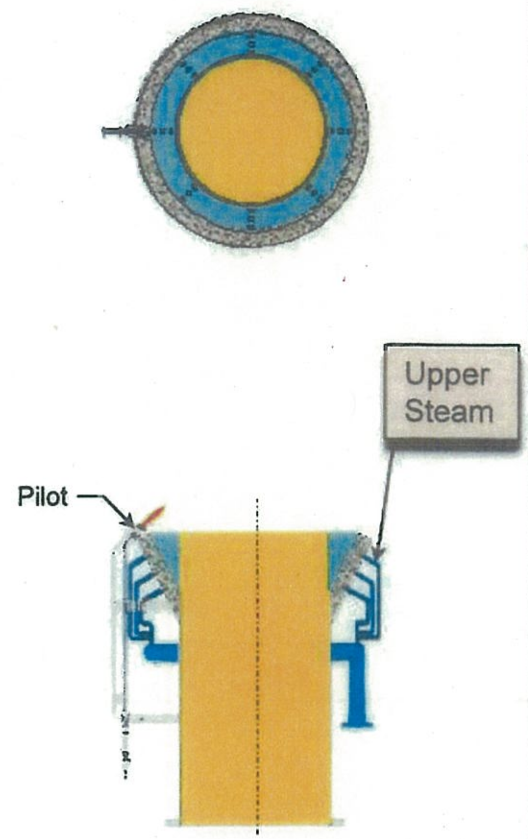

Type IA
Stability Tab
Pilot
Upper Steam
Center Steam
Type IB
Pilot
Stability Tab
Upper Steam
Type II
Exit Lower Steam/Air Mixture
Steam/Air Tubes
Pilot
Stability Ring
Upper Steam
Lower Steam
Center Steam
Key:
Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

Appendix 1.1

Type III



Type IV



Key:
Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

APPENDIX C-1.2

GENERAL EQUATIONS

Equation 1: **"*Combustion Efficiency*" or "*CE*" (percent):**

$$CE = ([CO_2]/([CO_2] + [CO] + [OC])) * 100$$

where:

$[CO_2]$ = Concentration in volume percent or ppm-meters of carbon dioxide in the combusted gas immediately above the Combustion Zone

$[CO]$ = Concentration in volume percent or ppm-meters of carbon monoxide in the combusted gas immediately above the Combustion Zone

$[OC]$ = Concentration in volume percent or ppm-meters of the sum of all organic carbon compounds in the combusted gas immediately above the Combustion Zone, counting each carbon molecule separately where the concentration of each individual compound is multiplied by the number of carbon atoms it contains before summing (*e.g.*, 0.1 volume percent ethane shall count as 0.2 percent OC because ethane has two carbon atoms)

For purposes of using the *CE* equation, the unit of measurement for CO_2, CO, and OC must be the same; that is, if "volume percent" is used for one compound, it must be used for all compounds. "Volume percent" cannot be used for one or more compounds and "ppm-meters" for the remainder.

Equation 2: **[Reserved].**

Equation 3: ***"Total Steam Mass Flow Rate" or "$\dot{m}_s$":***

$$\dot{m}_s = Q_{s\text{-}rate} \times (18/385.3)$$

where:

$Q_{s\text{-}rate}$ = Total Steam Volumetric Flow Rate

385.3 = Conversion factor, standard cubic feet per pound-mole

Equation 4: **"*Vent Gas Mass FlowRate*" or "$Q_{mass\text{-}rate}$":**

$$Q_{mass\text{-}rate} = Q_{vg} \times (MW_{vg}/385.3)$$

where:

$Q_{vg\text{-}rate}$ = Vent Gas Volumetric Flow Rate

MW_{vg} = Molecular Weight, in pounds per pound-mole, of the Vent Gas, as measured by the Vent Gas Average Molecular Weight Monitoring System or Analyzer

385.3 = Conversion factor, standard cubic feet per pound-mole

Equation 5: ***"Maximum Tip Velocity" or "V_{max}":***

$$Log_{10}(V_{max}) = (NHV_{vg} + 1{,}212)/850$$

where:

V_{max} = Maximum allowed Flare Tip Velocity, ft/sec

NHV_{vg} = Net Heating Value of Vent Gas, as determined by Equation 1 or Equation 2 in Appendix C – 1.3, BTU/scf.

1,212 = Constant.

850 = Constant.

Equation 6: Mass Flow to Volumetric Flow Rate or "Q_{vol}":

$$Q_{vol} = (Q_{mass} \times 385.3)/MWt$$

where:

Q_{vol} = Volumetric flow rate, standard cubic feet per second

Q_{mass} = Mass flow rate, pounds per second

385.3 = Conversion factor, standard cubic feet per pound-mole

MWt = Molecular weight of the gas at the flow monitoring location, pounds per pound-mole

Equation 7: ***"15-Minute Block Average Tip Velocity" or "V_{tip}":***

$$V_{tip} = Q_{cum}/(Area \times 900)$$

where:

V_{tip} = Flare Tip Velocity, feet per second.

Q_{cum} = Cumulative volumetric flow over 15-minute Block Average Period, actual cubic feet.

Area	=	Unobstructed Cross Sectional Area of the Flare Tip, square feet.
900	=	Conversation factor, seconds per 15-minute Block Average

APPENDIX C-1.3

Determine the Net Heating Value of the Vent Gas (NHV_{vg})

If compositional analysis data are collected as provided in Paragraphs 118.a and 118.b, the Settling Defendants shall determine the NHV_{vg} of a specific sample using the following equation.

$$NHV_{vg} = \sum_{i=1}^{n} (x_i \cdot NHV_i) \qquad \textit{Equation 1}$$

where:

NHV_{vg}	=	Net Heating Value of Vent Gas, BTU/scf.
i	=	Individual component in Vent Gas.
n	=	Number of components in Vent Gas.
x_i	=	Concentration of component i in Vent Gas, volume fraction.
NHV_i	=	Net Heating Value of component i according to Table 1 of this appendix, BTU/scf. If the component is not specified in Table 1 of this appendix, the heats of combustion may be determined using any published values where the net enthalpy per mole of offgas is based on combustion at 25 °C and 1 atmosphere (or constant pressure) with offgas water in the gaseous state, but the standard temperature for determining the volume corresponding to one mole of Vent Gas is 20° C.

Direct Net Heating Value by Calorimeter Data without Hydrogen Analyzer

If direct Net Heating Value by calorimeter monitoring data are collected as provided in Paragraph 118.c but a hydrogen concentration monitor is not used, the Settling Defendants shall use the direct output of the monitoring system(s) (in BTU/scf) to determine NHV_{vg} for the sample.

Direct Net Heating Value by Calorimeter Data with Hydrogen Analyzer

If direct Net Heating Value by calorimeter monitoring data are collected as provided in Paragraph 118.c and hydrogen concentration monitoring data are collected as provided in Paragraph 118.d, the Settling Defendants shall use the following equation to determine NHV_{vg} for each sample measured via the Net Heating Value calorimeter.

$$NHV_{vg} = NHV_{measured} + 938x_{H2}$$ ***Equation 2***

where:

NHV_{vg}	=	Net Heating Value of Vent Gas, BTU/scf.
$NHV_{measured}$	=	Net Heating Value of Vent Gas stream as measured by the continuous Net Heating Value calorimeter, BTU/scf.
x_{H2}	=	Concentration of hydrogen in Vent Gas at the time the sample was input into the Net Heating Value calorimeter, volume fraction.
938	=	Net correction for the measured heating value of hydrogen (1,212 – 274), BTU/scf.

Required Time Period for 15-Minute Block Averages

Use set 15-minute time periods starting at 12 midnight to 12:15 AM, 12:15 AM to 12:30 AM and so on concluding at 11:45 PM to midnight when calculating 15-minute Block Averages.

Monitoring Elections

When a continuous monitoring system is used as provided in Paragraphs 118.a or 118.c and, if applicable, 118.d, the Settling Defendants may elect to determine the 15-minute Block Average NHV_{vg} using either the feed-forward or direct calculation methods below. The Settling Defendants may choose to comply using the feed-forward calculation method for some Flares at the petroleum refinery and comply using the direct calculation method for other Flares. However, for each Flare, the Settling Defendants must elect one calculations method that will apply at all times, and use that method for all continuously monitored Flare vent streams associated with that Flare. If the Settling Defendants intend to change the calculation method that applies to the Flare, the Settling Defendants must notify the EPA and Applicable State Co-Plaintiff 30 Days in advance of such a change.

Feed-Forward Calculation Method

When calculating NHV_{vg} for a specific 15-minute block:

Use the results from the first sample collected during an event, (for periodic Vent Gas flow events) for the first 15-minute block associated with that event. If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute Block Period starts, use the results from the first sample collected during an event for the second 15-minute Block Period associated with that event. For all other cases, use the results that are available from the most recent sample prior to the 15-minute Block Period for that 15-minute Block Period for all Vent Gas streams. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute Block Period from 12:45 a.m. to 1:00 a.m.

Direct Calculation Method

When calculating NHV_{vg} for a specific 15-minute Block Period:

If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute Block Period starts, use the results from the first sample collected during an event for the first 15-minute Block Period associated with that event. For all other cases, use the arithmetic average of all NHV_{vg} measurement data results that become available during a 15-minute block to calculate the 15-minute Block Average for that period. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute Block Period from 12:30 a.m. to 12:45 a.m.

Grab Sample Option

When grab samples are used to determine Vent Gas composition:

Use the analytical results from the first grab sample collected for an event for all 15-minute Block Periods from the start of the event through the 15-minute block prior to the 15-minute block in which a subsequent grab sample is collected. Use the results from subsequent grab sampling events for all 15 minute Block Periods starting with the 15-minute Block Period in which the sample was collected and ending with the 15-minute Block Period prior to the 15-minute Block Period in which the next grab sample is collected. For the purpose of this requirement, use the time the sample was collected rather than the time the analytical results become available.

Measurement of Separate Gas Streams

If the Settling Defendants monitor separate gas streams that combine to comprise the total Vent Gas flow, the 15-minute Block Average Net Heating Value shall be determined separately for each measurement location according to the methods above and a flow-weighted average of the gas stream Net Heating Values shall be used to determine the 15-minute Block Average Net Heating Value of the cumulative Vent Gas.

Calculation Methods for Determining Combustion Zone Net Heating Value (NHV_{cz})

Direct Calculation Method

Except as specified in Paragraph 139.b.ii for the feed-forward calculation method, determine the 15-minute Block Average NHV_{CZ} based on the 15-minute Block Average Vent Gas and assist gas flow rates using Equation 3. For periods when there is neither Assist Steam flow nor Premix Assist Air flow, $NHV_{cz} = NHV_{vg}$.

$$NHV_{cz} = \frac{Q_{vg} \times NHV_{vg}}{\left(Q_{vg} + Q_S + Q_{a,premix}\right)}$$ ***Equation 3***

where:

NHV_{cz} = Net Heating Value of Combustion Zone Gas, BTU/scf.

NHV_v = Net Heating Value of Vent Gas for the 15-minute Block Period, BTU/scf.

Q_v = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Q_s = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.

Feed-Forward Calculation Method

Flares that use the feed-forward calculation methodology below and that monitor gas composition or Net Heating Value in a location representative of the cumulative Vent Gas stream and that directly monitor Supplemental Gas flow additions to the Flare must determine the 15-minute Block Average NHV_{cz} using Equation 4.

$$NHV_{cz} = \frac{\left(Q_{vg} - Q_{NG2} + Q_{NG1}\right) \times NHV_{vg} + \left(Q_{NG2} - Q_{NG1}\right) \times NHV_{ng}}{\left(Q_{vg} + Q_S + Q_{a,premix}\right)}$$ ***Equation 4***

where:

NHV_{cz} = Net Heating Value of Combustion Zone Gas, BTU/scf.

NHV_{vg} = Net Heating Value of Vent Gas for the 15-minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Q_{NG2} = Cumulative volumetric flow of Supplemental Gas to the Flare during the 15-minute Block Period, scf.

Q_{NG1} = Cumulative volumetric flow of Supplemental Gas to the Flare during the previous 15-minute Block Period, scf. For the first 15-minute Block Period of an event, use the volumetric flow value for the current 15-minute Block Period, i.e., $Q_{NG1}=Q_{NG2}$.

NHV_{NG}	=	Net Heating Value of Supplemental Gas to the Flare for the 15-minute Block Period determined according to the requirements in Paragraph 118.e, BTU/scf.
Q_s	=	Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.
$Q_{a,premix}$	=	Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.

Calculation Methods for Determining the Net Heating Value Dilution Parameter (NHV_{dil})

The Settling Defendants shall determine the Net Heating Value Dilution Parameter (NHV_{dil}) as specified below for Flares using either the feed-forward calculation method or the direct calculation method, as applicable.

Calculation Methods for Determining the Net Heating Value Dilution Parameter (NHV_{dil})

Direct Calculation Method

For Flares using the direct calculation method, determine the 15-minute Block Average NHV_{dil} based on the 15-minute Block Average Vent Gas and Perimeter Assist Air flow rates using Equation 5 only during periods when the Perimeter Assist Air is used. For 15-minute Block Periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute Block Average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{Q_{vg} \times Diam \times NHV_{vg}}{\left(Q_{vg} + Q_S + Q_{a,premix} + Q_{a,perimeter}\right)} \qquad \textbf{\textit{Equation 5}}$$

where:

NHV_{dil}	=	Net Heating Value Dilution Parameter, BTU/ft^2.
NHV_{vg}	=	Net Heating Value of Vent Gas determined for the 15-minute Block Period, BTU/scf.
Q_{vg}	=	Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.
Diam	=	Effective diameter of the Unobstructed Cross Sectional Area of the Flare Tip for Vent Gas flow, ft. Use the area as determined in Paragraph 135.b.ii.a and determine the diameter as Diam = 2 x $(\text{Area}/\pi)^{0.5}$.

Q_s = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.

$Q_{a.premix}$ = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.

$Q_{a.perimeter}$ = Cumulative volumetric flow of Perimeter Assist Air during the 15-minute Block Period, scf.

Feed-Forward Calculation Method

Settling Defendants operating Flares that use the feed-forward calculation methodology and that monitor gas composition or Net Heating Value in a location representative of the cumulative Vent Gas stream and that directly monitor Supplemental Gas flow additions to the Flare must determine the 15-minute Block Average NHV_{dil} using the following equation only during periods when the Perimeter Assist Air is used. For 15-minute Block Periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute Block Average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{\lfloor (Q_{vg} - Q_{NG2} + Q_{NG1}) \times NHV_{vg} + (Q_{NG2} - Q_{NG1}) \times NHV_{NG} \rfloor \times Diam}{\left(Q_{vg} + Q_S + Q_{a.premix} + Q_{a.perimeter}\right)} \qquad \textbf{\textit{Equation 6}}$$

where:

NHV_{dil} = Net Heating Value Dilution Parameter, BTU/ft^2.

NHV_{vg} = Net Heating Value of Vent Gas determined for the 15-minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Q_{NG2} = Cumulative volumetric flow of Supplemental Gas to the Flare during the 15-minute Block Period, scf.

Q_{NG} = Cumulative volumetric flow of Supplemental Gas to the Flare during the previous 15-minute Block Period, scf. For the first 15-minute Block Period of an event, use the volumetric flow value for the current 15-minute Block Period, i.e., $Q_{NG1} = Q_{NG2}$.

NHV_{NG} = Net Heating Value of Supplemental Gas to the Flare for the 15-minute Block Period determined according to the requirements in Paragraph 118.e, BTU/scf.

Diam = Effective diameter of the Unobstructed Cross Sectional Area of the Flare Tip for Vent Gas flow, ft. Use the area as determined in Paragraph 135.d.ii.aand determine the diameter as Diam = 2 x (Area/π)$^{0.5}$

Q_s	=	Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.
$Q_{a.premix}$	=	Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.
$Q_{a.perimeter}$	=	Cumulative volumetric flow of Perimeter Assist Air during the 15-minute Block Period, scf.

Table 1

Individual Compound Properties

Component	Molecular Formula	MWi (pounds per pound-mole)	CMNi (mole per mole)	NHVi (British thermal units per standard cubic	LFLi (volume %)
Acetylene	C_2H_2	26.04	2	1,404	2.5
Benzene	C_6H_6	78.11	6	3,591	1.3
1,2-Butadiene	C_4H_6	54.09	4	2,794	2.0
1,3-Butadiene	C_4H_6	54.09	4	2,690	2.0
iso-Butane	C_4H_{10}	58.12	4	2,957	1.8
n-Butane	C_4H_{10}	58.12	4	2,968	1.8
cis-Butene	C_4H_8	56.11	4	2,830	1.6
iso-Butene	C_4H_8	56.11	4	2,928	1.8
trans-Butene	C_4H_8	56.11	4	2,826	1.7
Carbon Dioxide	CO_2	44.01	1	0	∞
Carbon Monoxide	CO	28.01	1	316	12.5
Cyclopropane	C_3H_6	42.08	3	2,185	2.4
Ethane	C_2H_6	30.07	2	1,595	3.0
Ethylene	C_2H_4	28.05	2	1,477	2.7
Hydrogen	H_2	2.02	0	1,212[a]	4.0
Hydrogen Sulfide	H_2S	34.08	0	587	4.0
Methane	CH_4	16.04	1	896	5.0
Methyl-	C_3H_4	40.06	3	2,088	1.7
Nitrogen	N_2	28.01	0	0	∞
Oxygen	O_2	32.00	0	0	∞
Pentane+ (C5+)	C_5H_{12}	72.15	5	3,655	1.4
Propadiene	C_3H_4	40.06	3	2,066	2.16
Propane	C_3H_8	44.10	3	2,281	2.1
Propylene	C_3H_6	42.08	3	2,150	2.4
Water	H_2O	18.02	0	0	∞

[a] The theoretical Net Heating Value for hydrogen is 274 BTU/scf, but for the purposes of the Flare requirement in this Consent Decree, a Net Heating Value of 1,212 BTU/scf shall be used.

The sources for values in this table are Appendix to Subpart CC of Part 63 Table 12.

APPENDIX C-1.4

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APPENDIX C-1.5

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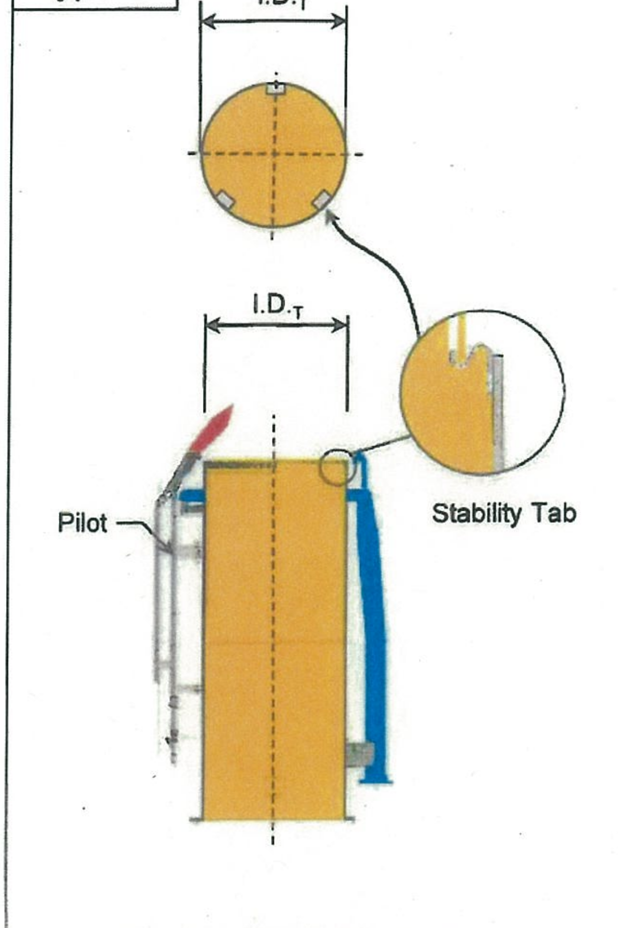
APPENDIX C-1.6

APPENDIX 1.6

Type I



$$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - (X_T * A_{ST})$$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

X_T = Number of Stability Tabs

A_{ST} = Area of a Stability Tab

Example: $I.D._T$ = 41.5 inches

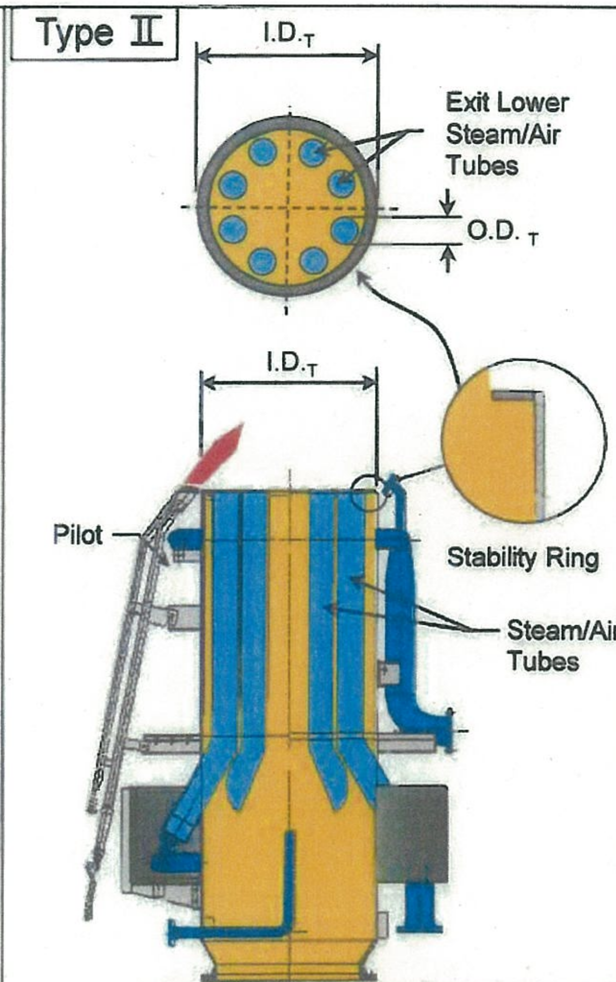
$X_T = 3$

A_{ST} = 3 Sq. inches

$A_{tip\text{-}unob} = \pi(41.5)^2/4 - (3 * 3)$

$A_{tip\text{-}unob}$ = 1344 Sq. inches

Type II



$$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - A_{ST} - N_T * \pi * (O.D._T)^2/4$$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

A_{ST} = Area of Stability Ring

$O.D._T$ = Outside Diameter of Steam/Air Tubes

N_T = Number of Steam/Air Tubes

Example: $I.D._T$ = 47.5 inches

A_{ST} = 100 Sq. inches

$O.D._T$ = 6.5 inches

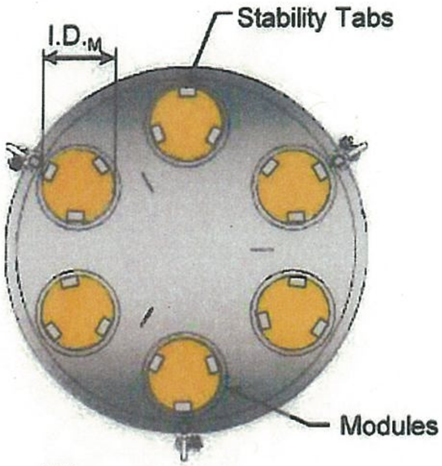
$N_T = 8$

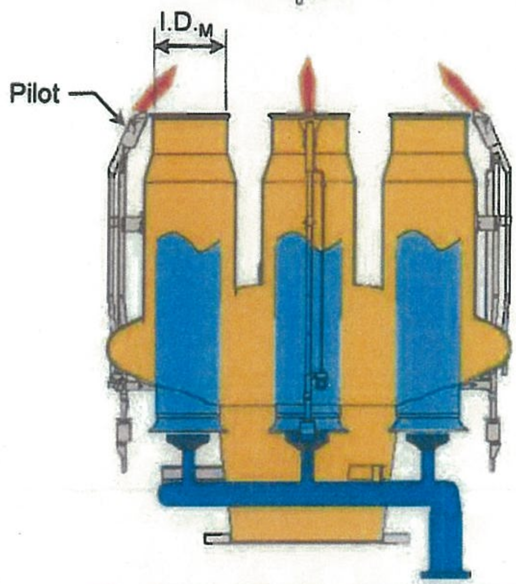
$A_{tip\text{-}unob} = \pi\ (47.5)^2/4 - 100 - 8 * \pi * (6.5)^2/4$

$A_{tip\text{-}unob}$ = 1322 Sq. inches

APPENDIX 1.6

Type III





$A_{tip-unob} = N_M * (\pi*(I.D._M)^2/4 - X_T * A_{ST})$

Where: $A_{tip-unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._M$ = Inside Diameter of One Tip Module

N_M = Number of Modules

X_T = Number of Stability Tabs per Module

A_{ST} = Area of a Stability Tab

Example: $I.D._M$ = 17 inches

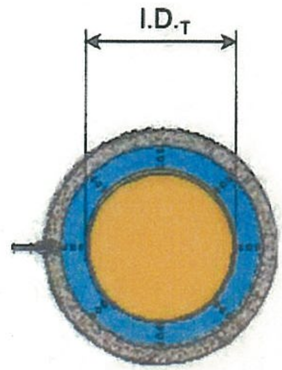
$N_M = 6$ $X_T = 3$

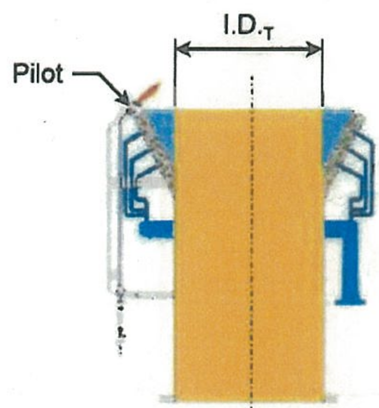
A_{ST} = 3 Sq. inches

$A_{tip-unob} = 6 * (\pi*(17)^2/4 - 3 * 3)$

$A_{tip-unob}$ = 1308 Sq. inches

Type IV





$A_{tip-unob} = \pi(I.D._T)^2/4$

Where: $A_{tip-unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter of Flare Tip

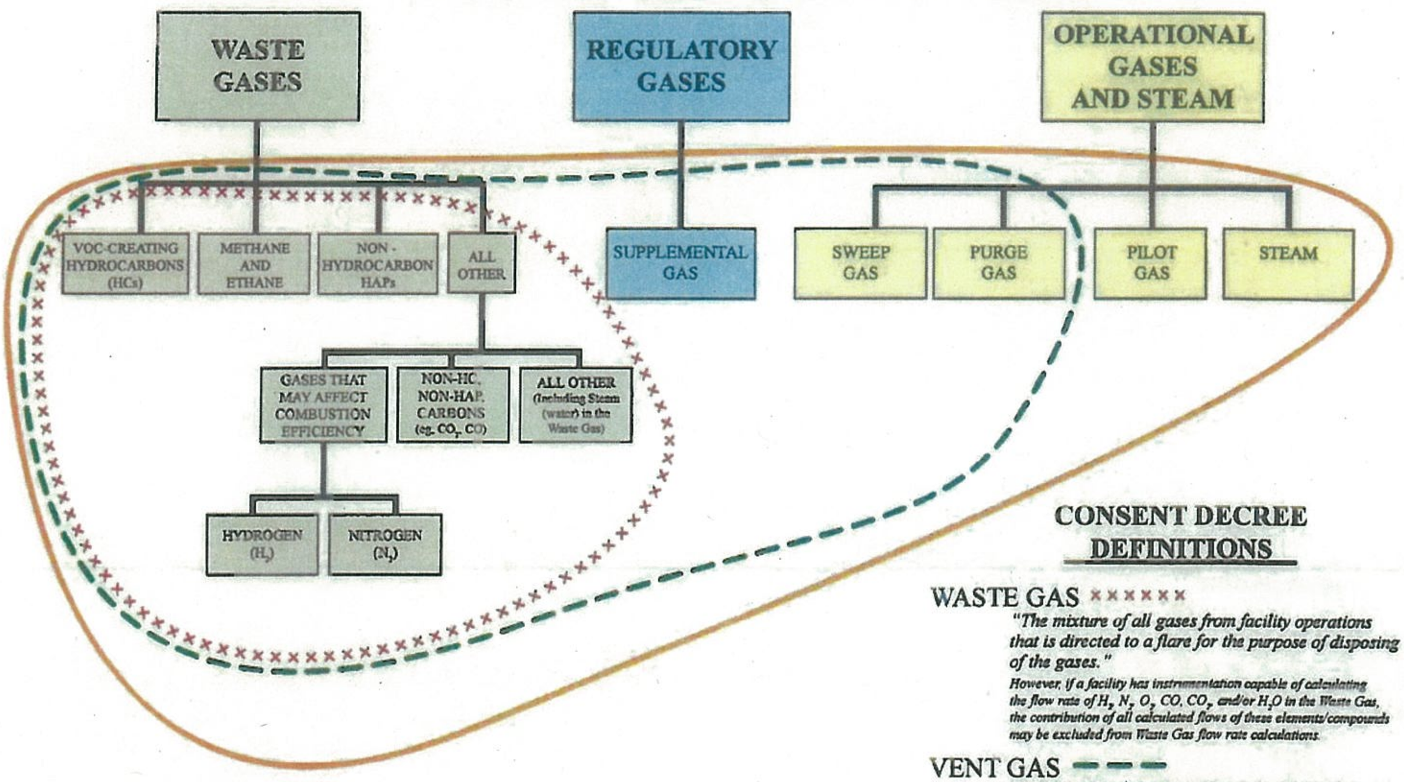
Example: $I.D._T$ = 41.5 inches

$A_{tip-unob} = \pi\ (41.5)^2/4$

$A_{tip-unob}$ = 1353 Sq. inches

APPENDIX
C-1.7

DEPICTION OF GASES ASSOCIATED WITH STEAM-ASSISTED FLARES



CONSENT DECREE DEFINITIONS

WASTE GAS ××××××

"The mixture of all gases from facility operations that is directed to a flare for the purpose of disposing of the gases."

However, if a facility has instrumentation capable of calculating the flow rate of H_2, N_2, O_2, CO, CO_2, and/or H_2O in the Waste Gas, the contribution of all calculated flows of these elements/compounds may be excluded from Waste Gas flow rate calculations.

VENT GAS

"The mixture of all gases found prior to the flare tip. This includes all Waste Gas, Supplemental Gas, Sweep Gas, and Purge Gas."

COMBUSTION ZONE GAS

"The mixture of all gases and steam found just after the flare tip. This includes all Vent Gas, Pilot Gas, and Total Steam."

APPENDIX 1.7

APPENDIX C-1.8

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APPENDIX C-1.9

LIST OF COMPOUNDS A GAS CHROMATOGRAPH MUST BE CAPABLE OF SPECIATING*

Unless an alternative monitoring option is selected from Paragraph 118, the gas chromatograph must be capable of speciating the Vent Gas into the following except as noted as optional below:

1. Hydrogen
2. Carbon monoxide (optional)
3. Methane
4. Ethane
5. Ethene (aka: ethylene)
6. Propane
7. Propene (aka: propylene)
8. 2-Methylpropane (aka: iso-butane)
9. Butane (aka: n-butane)
10. Butenes and 1,3 butadiene (these constituents will be measured on the same column and the reported result will be one value: the sum of the constituents. A Net Heating Value of 2,690 btu/scf will be assumed.)
11. N-pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.
12. Acetylene (optional)
13. Propadiene (optional)
14. Hydrogen sulfide (optional)

*Outputs from the gas composition analyzer shall be on a mole percent or volume percent basis, except hydrogen sulfide may be on a parts per million basis.

APPENDIX C-1.10

EQUIPMENT AND INSTRUMENTATION TECHNICAL SPECIFICATIONS AND QUALITY ASSURANCE/QUALITY CONTROL REQUIREMENTS

These technical specifications are the minimally acceptable standards. Standards better than or beyond these are acceptable.

I. VENT GAS FLOW METER

1. Velocity Range: 0.1–250 ft/sec

2. Repeatability:

   ± 10% of reading over the velocity range 0.1 to 1.0 ft/s

   ± 1% of reading over the velocity range >1.0 to 250 ft/s

3. Design Accuracy: ± 5% initially to 40%, 60%, and 90% of monitor full scale as certified by the manufacturer

4. Operational Accuracy: ± 20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second). ± 5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second).

5. Installation: Applicable AGA, ANSI, API, or equivalent standard

6. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

7. QA/QC: Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the meter has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
8. Pressure and Temperature Sensors: *See* Part IV below.

II. VENT GAS AVERAGE MOLECULAR WEIGHT ANALYZER (may be part of the Vent Gas Flow Meter)

Molecular Weight Range and Accuracy: 2 to 120 gr/grmol, ± 2%

III. STEAM FLOW METERS

For the new steam flow meters that must be installed by the date in Appendix 2.1:

1. Repeatability: ± 5% of reading over the range of the instrument

2. Accuracy: ± 5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow. ± 5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow. ± 5 percent over the normal range measured for mass flow.

   a. Installation: Applicable AGA, ANSI, API, or equivalent standard

   b. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

   c. QA/QC: Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

IV. VENT GAS FLOW METERS: PRESSURE AND TEMPERATURE SENSORS

1. Temperature monitor accuracy: ± 1 percent over the normal range of temperature measured, expressed in degrees Celsius C, or 2.8 degrees C, whichever is greater.

2. Temperature monitor QA/QC: Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor. Record the results of each calibration check and inspection.

3. Locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.

4. Pressure monitor accuracy: ± 5 percent over the normal range or 0.12 kilopascals (0.5 inches of water column), whichever is greater.

5. Pressure monitor QA/QC: Review pressure sensor readings at least once a week for straight line (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated. Using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following a period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rates pressure or install a new pressure sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor. Record the results of each calibration check and inspection.

6. Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.

V. <u>NET HEATING VALUE BY GAS CHROMATOGRAPH</u>

A. <u>General</u>

1. Accuracy: As specified in Performance Specification 9 of 40 C.F.R. Part 60, Appendix B.

2. 8-Hour Repeatability:

   ± 0.5% of full scale for ranges between 2-100% of full scale;
   ± 1% of full scale for ranges between 0.05-2% of full scale;
   ± 2% of full scale for ranges between 50-500 ppm;
   ± 3% of full scale for ranges between 5-50 ppm;
   ± 5% of full scale for ranges between 0.5-5 ppm.

3. The minimum sampling frequency shall be one sample every 15 minutes.

4. The gas chromatograph shall be capable of speciating all gas constituents listed in Appendix 1.9, except those listed as optional or if an alternative monitoring option is selected within Paragraph 118.

5. The sampling line temperature must be maintained at a minimum temperature of 60°C (rather than 120°C).

6. Where technically feasible, the sampling location should be at least two equivalent duct diameters downstream from the nearest control device, point of pollutant generation, or other point at which a change in the

pollutant concentration or emission rate occurs. The location should not be close to air in-leakages. Where technically feasible, the location should also be at least 0.5 diameters upstream from the exhaust or control device.

A. Calibration Standards: Net Heating Value and Analyte Measurements

For the Net Heating Value and analyte measurements, the gas chromatograph shall be operated and maintained in accordance with Performance Specification 9 ("PS9") of Appendix B of 40 C.F.R. Part 60 except:

1. Follow the procedure in Performance Specification 9 of 40 C.F.R. Part 60, Appendix B, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly).

2. Unless an alternative monitoring option is selected from Paragraph 118, the analytes to be used are except as noted as optional below:

   a. Hydrogen
   b. Carbon monoxide (optional)
   c. Methane
   d. Ethane
   e. Ethene (aka: ethylene)
   f. Propane
   g. Propene (aka: propylene)
   h. 2-Methylpropane (aka: iso-butane)
   i. Butane (aka: n-butane)
   j. Butenes and 1,3 butadiene (these constituents will be measured on the same column and the reported result will be one value: the sum of the constituents.
   k. N-pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.
   l. Acetylene (optional)
   m. Propadiene (optional)
   n. Hydrogen sulfide (optional)

3. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the Settling Defendants must calibrate the instrument on all of the gases.

VI. NET HEATING VALUE BY CALORIMETER

A. General

1. Accuracy: ± 2% of span.

2. Repeatability: ± 1% of reading over full scale.

3. The minimum sampling frequency shall be one sample every 15 minutes.

4. Where feasible, select a sampling location at least two equivalent diameters downstream from and 0.5 equivalent diameters upstream from the nearest disturbance. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration or emission rate occurs.

B. <u>Calibration Standards and Quality Assurance</u>

The Net Heating Value calorimeter shall be operated and maintained in accordance with the following:

1. Calibration requirements should follow manufacturer's recommendations at a minimum

2. <u>Temperature Control</u>. Heat and/or cool the sampling system as necessary to ensure proper year-round operation.

VII. <u>HYDROGEN ANALYZER</u>

A. <u>General</u>

1. Accuracy: ± 2 percent over the concentration measured or 0.1 volume percent whichever is greater.

2. The minimum sampling frequency shall be one sample every 15 minutes.

3. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration occurs.

B. <u>Calibration Standards and Quality Assurance</u>

Calibration requirements should follow manufacturer's recommendations minimum.

VIII. CALCULATION OF INSTRUMENT DOWNTIME

A. Gas Chromatograph

1. For purposes of calculating the 5% of instrument downtime allowed in any six month period pursuant to Paragraph 123 and 150 of the Consent Decree, the time used for gas chromatograph calibration and validation activities required by Subparagraph V.B. of this Appendix may be excluded.

2. Any hour that meets the requirements as set forth below shall not be counted toward instrument downtime. Specifically:

   a. For a full operating hour (any clock hour where the Flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas)), if there are at least four valid data points to calculate the hourly average (that is, one data point in each of the 15-minute sector of the hour), then there is no period of instrument downtime;

   b. For a partial operating hour (any clock hour where the Flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas)), if there is at least one valid data point in each 15-minute sector of the hour in which the Flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) to calculate the hourly average, then there is no period of instrument downtime; and

   c. For any operating hour in which required maintenance or Quality Assurance activities on the instruments or monitoring systems associated with the Flare are performed:

      i. If the Flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) in two or more 15-minute quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

      ii. If the Flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) in only one 15-minute quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.

B. <u>Net Heating Value Calorimeter</u>

1. For purposes of calculating the 5% of instrument downtime allowed in any six month period pursuant to Paragraph 123 and 150 of the Consent Decree, the time used for NHV calorimeter calibration and validation activities required by Subparagraph V.B.1 of this Appendix may be excluded.

2. Any hour that meets the requirements of 40 C.F.R. § 60.13(h)(2) shall not be counted toward instrument downtime. Specifically:

   (i) For a full operating hour (any clock hour where the Flare is Available for Operation for 60 minutes), if there are at least four valid data points to calculate the hourly average (that is, one data point in each of the 15-minute quadrants of the hour), then there is no period of instrument downtime;

   (ii) For a partial operating hour (any clock hour where the Flare is Available for Operation for less than 60 minutes), if there is at least one valid data point in each 15-minute quadrant of the hour in which the Flare is Available for Operation to calculate the hourly average, then there is no period of instrument downtime; and

   (iii) For any operating hour in which required maintenance or Quality Assurance activities on the instruments or monitoring systems associated with the Flare are performed:

      (A) If the Flare is Available for Operation in two or more quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

      (B) If the Flare is Available for Operation in only one quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.

APPENDIX C-1.11

WASTE GAS MAPPING:
LEVEL OF DETAIL NEEDED TO SHOW HEADERS AND
FLARING PROCESS UNIT HEADERS

Purpose:

Waste Gas mapping is required in order to identify the source(s) of Waste Gas entering each Covered Flare. Waste Gas mapping can be done using instrumentation, isotopic tracing, acoustic monitoring, and/or engineering estimates for all sources entering a Flare header (e.g. pump seal purges, sample station purges, compressor seal nitrogen purges, relief valve leakage, and other sources under normal operations). Appendix 1.11 outlines what needs to be included as the Waste Gas Mapping section within the Initial Flare Management Plan ("Initial FMP")

Waste Gas Mapping Criteria:

For purposes of Waste Gas mapping, a main header is defined as the last pipe segment prior to the Flare knock out drum. Flaring Process Unit headers are defined as pipes from inside the battery limits of each process unit that connect to the main header. For Flaring Process Unit headers that are greater than or equal to six (6) inches in diameter, flow ("Q") must be identified and quantified if it is technically feasible to do so. In addition, all sources feeding each Flaring Process Unit header must be identified and listed in a table, but not necessarily individually quantified. For Flaring Process Unit headers that are less than six (6) inches in diameter, sources must be identified, but they do not need to be quantified.

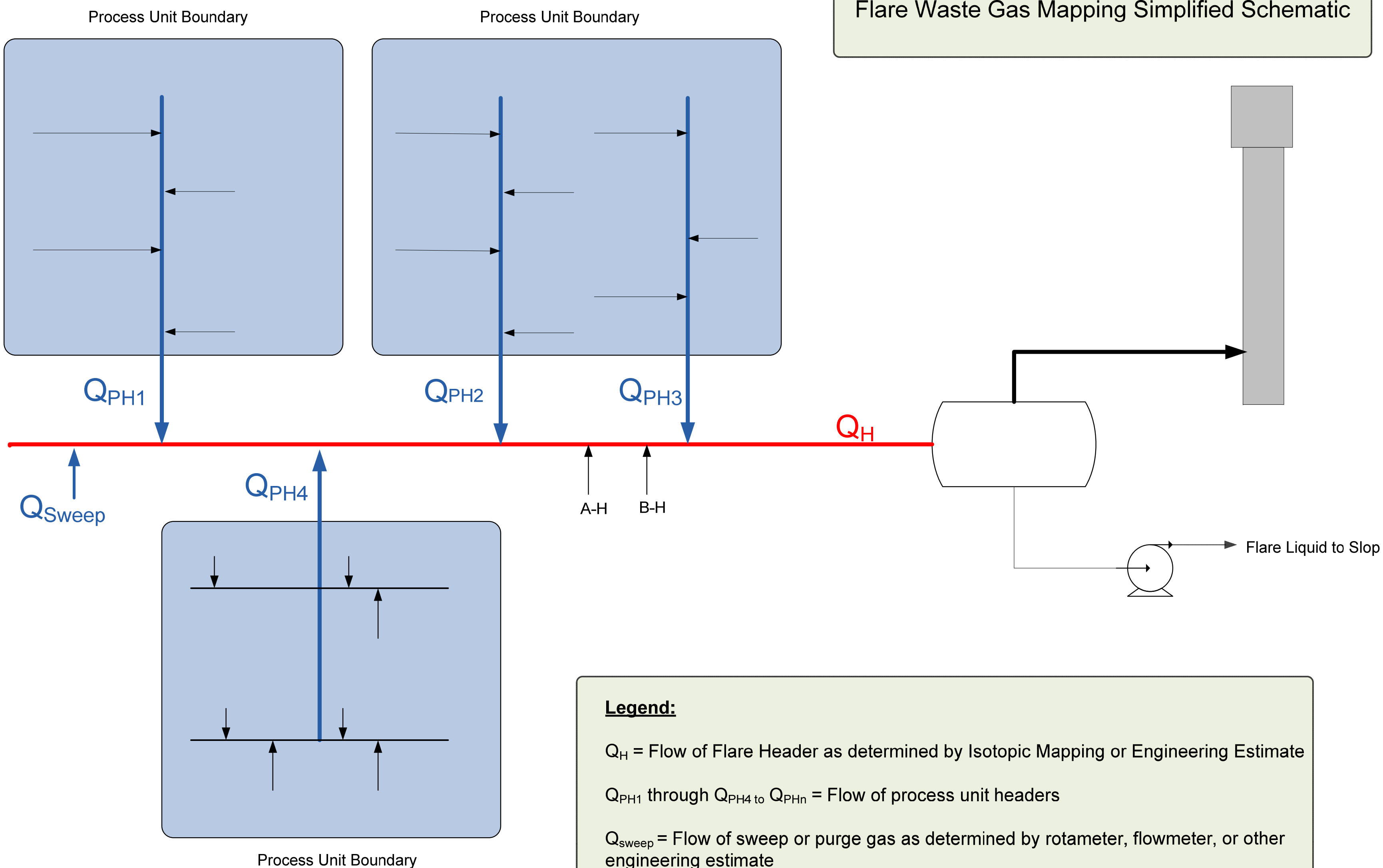
Waste Gas Mapping Submission Requirements:

For each Covered Flare, the following shall be included within the Waste Gas Mapping section of the Initial FMP:

1. Simplified schematic consistent with the example schematic included on the second page of this Appendix.

2. Table of all sources connected to each Flare main header and Flaring Process Unit header consistent with the Table included on the third page of this Appendix.

Flare Waste Gas Mapping Simplified Schematic



Legend:

Q_H = Flow of Flare Header as determined by Isotopic Mapping or Engineering Estimate

Q_{PH1} through $Q_{PH4\ to}$ Q_{PHn} = Flow of process unit headers

Q_{sweep} = Flow of sweep or purge gas as determined by rotameter, flowmeter, or other engineering estimate

Table 1: Example of Flare Source Description Table

Flaring Process Unit Header	Sources	Detailed Source Description
QPH1 (Ex: FCCU Gas Con Unit)	3 PSVs	PSV-14 on 110-D-5 Gas Con Absorber PSV-12 on 110-D-1 Amine Scrubber PSV-7 on 110-F-1 Batch Caustic Vessel
	2 Pump Seal Purges	110-G-1 LPG Pump 110-G-2 Rich Amine Pump
	1 Sample Station	110-S-1 LPG
	1 PSV	PSV 17 on 112-D-1 Main Column
	1 Pressure Control Valve	PCV 21 – Emergency Wet Gas Compressor
	1 PSV	PSV-21 on Flush Oil Drum
	1 Pump Seal Purge	110-G-23 Slurry Oil Pump
QPH2 (Ex: Gas Oil Treater)	Continue same as QPH1	Continue same as QPH1
QPH3	Continue same as QPH1	Continue same as QPH1
QPH4	Continue same as QPH1	Continue same as QPH1
A-H	1 PSVs	PSV-17 on 109-E-42 Slurry Heat Exchanger
B-H	2 Pump Seal Purges	110-G-3 Gas Oil Feed 110-G-4 Main Column Reflux

APPENDIX C-1.12

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APPENDIX C-1.13

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APPENDIX C-1.14

DETERMINING REFINERY-SPECIFIC AND INDUSTRY-AVERAGE COMPLEXITY THROUGH USE OF THE NELSON COMPLEXITY INDEX

DEFINITIONS:

"Applicable EIA Annual Refinery Publication" shall mean the Annual EIA Refinery Publication that was the most recent one posted on EIA's website prior to a refinery's request for an increase in flaring caps.

"Applicable Form EIA-820" shall mean the Form EIA-820 that forms the source for the requesting refinery's capacity information that is summarized and compiled in the Applicable Annual EIA Refinery Publication.

> *For example, if a refinery requests an increase in flaring caps in March of 2015, the "Applicable Form EIA-820," is the Form EIA-820 that the refinery submitted prior to February 15, 2014, for its capacities as of January 1, 2014, (and not the Form EIA-820 that the Refinery submitted prior to February 15, 2015, for its capacities as of January 1, 2015). This is because the Applicable EIA Annual Refinery Publication is the one published in June of 2014 (i.e., the last one published prior to March of 2015).*

"Applicable O&GJ Refining Survey" shall mean the survey that is published in December of the year prior to the year of the Applicable EIA Annual Refinery Publication.

> *For example, if the Applicable EIA Annual Refinery Publication is the one published in June of 2014, then the Applicable O&GJ Refinery Survey is the one published in December of 2013 for capacities as of January 1, 2014.*

"EIA" shall mean the United States Energy Information Agency.

"EIA Annual Publication of the Number and Capacity of Petroleum Refineries" or "EIA Annual Refinery Publication" shall mean the information posted on EIA's website on approximately June 21 of each year that compiles and summarizes the data submitted on the Form EIA-820s that each refinery submits prior to February 15 of that year. The most recent EIA Annual Refinery Publication is found at http://www.eia.gov/petroleum/refinerycapacity.

"Form EIA-820" shall mean the annual report that each refinery is required to submit to the EIA prior to February 15 of each year. The "Report Year" of a Form EIA-820 refers to the capacities that exist as of January 1 of the "Report Year." A copy of a typical Form EIA-820 is Attachment 1 to this Appendix.

"Oil & Gas Journal Worldwide Refining Survey" or "O&GJ Refining Survey" shall mean the survey that the Oil & Gas Journal publishes in December of each year that lists refining capacities as of January 1 of the following year. A copy of the national refining capacities listed in the December 2014 O&GJ Refining Survey for January 1, 2015 is Attachment 2 to this Appendix.

REFINERY COMPLEXITY: The complexity of the refinery is to be calculated using the following formula:

Equation 1

$$Complexity = \sum_{n=1}^{i} \left(\frac{NCI_i \times CAP_i}{CAP_{Dist}} \right)$$

Where:

NCI_i = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for Flaring Process Unit i.

CAP_i = The throughput capacity for the Refinery's process unit i in barrels per calendar day, which shall be determined as follows:

(a) for a process unit that is not new or modified and for which the Applicable EIA Annual Refinery Publication lists total US throughput for that process, the capacity, in barrels per calendar day, that the refinery reported for process i on Part 6 or Part 7/[1] of the Applicable Form EIA-820. If the refinery did not report the capacity of process i in "barrels per calendar day," but instead reported it in "barrels per stream day," then "barrels per stream day" will be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units; or

(b) for a process unit that is not new or modified, if and only if the Applicable EIA Annual Refinery Publication does not list total US throughput capacity for that process unit, then the refinery's capacity for that process unit, in barrels per calendar day, listed in the Applicable O&GJ Refining Survey.

(c) for a process unit that is new or modified, where the new or modified capacity was not reported on the Applicable Form EIA-820, the projected new or modified unit capacity that is set forth in the air permit application(s) for the post-Lodging modification.

CAP_{DIST} = The refinery's Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, which shall be determined as follows:

(a) if the post-Lodging modification does not affect the crude capacity, the Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, that the Refinery reported under "Total Operable" capacity on Part 5, Code 401[/1] of the Applicable Form EIA-820; or

(b) if the post-Lodging modification does affect crude capacity, the projected, new capacity set forth in the air permit application(s) for the post-Lodging modification.

[/1] The references to particular "Parts" or "Codes" of Form EIA-820 are to the Parts and Codes as they exist for the Form EIA-820 that was used for Report Year 2014. *See* Attachment 2. To that extent that the "Parts" or "Codes" on Form EIA-820 are changed in the future, the intent of the Parties is that the "Parts" and "Codes" of future forms that correspond most closely to those found on the Form EIA-820 for Report Year 2014 will be used.

INDUSTRY AVERAGE COMPLEXITY: The Industry Average Complexity is to be calculated using the following formula:

Equation 2

$$Industry\_Average\_Complexity = \sum_{n=1}^{i}\left(\frac{NCI_i \times ICAP_i}{ICAP_{Dist}}\right)$$

Where:

NCI_i = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for process unit i

$ICAP_i$ = Total US throughput capacity, in barrels per calendar day, for process unit i which shall be determined as follows:

(a) From the Applicable EIA Annual Refinery Publication, the total US capacity of process unit i in barrels per calendar day. For the total US capacity of those process units that the EIA lists only in "barrels per stream day" and not in "barrels per calendar day," the "barrels per stream day" shall be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units.[/2]

(b) If and only if the Applicable EIA Annual Refinery Publication does not list a total US throughput capacity for a process unit that the refinery operates, then the total US throughput capacity for that process unit listed in the Applicable O&GJ Refining Survey.

$ICAP_{DIST}$ = From the Applicable EIA Annual Refinery Publication, the total "Operable" US Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day.[3]

/2 For example, for catalytic reforming, the total US capacity as of January 1, 2015, is 3,392,641 barrels per calendar day. *See* EIA Annual Refinery Publication at page 46. Note that the capacity for catalytic reforming on page 1 of Attachment 1 should *not* be used because that is listed in "barrels per stream day," not bpcd. For vacuum distillation, the total US capacity for 2015 is 8,979,485 barrels per stream day. *See id.* at page 46. This figure would be converted to 8,530,051 barrels per calendar day (8,979,485 x .95).

/3 Total Operable US Atmospheric Crude Oil Distillation Capacity (total $ICAP_{DIST}$) of a January 1, 2015, is 17,967,088 barrels per calendar day. *See* id. at page 42.

Table 1: 2011 Nelson Complexity Index Coefficients

Refining Process	NCI Coefficients
Distillation Capacity	1.00
Vacuum Distillation	1.30
Thermal Processes	2.75
Coking	7.50
Catalytic Cracking	6.00
Catalytic Reforming	5.00
Catalytic Hydrocracking	8.00
Catalytic Hydrorefining	2.50
Catalytic Hydrotreating	2.50
Alkylation	10.00
Polymerization	10.00
Aromatics	20.00
Isomerization	3.00
Lubes	60.00
Asphalt	1.50
Hydrogen (MCFD)	1.00
Oxygenates	10.00
Sulfur Extraction	240.00

ATTACHMENT 1
TYPICAL FORM EIA-820

eia Independent Statistics & Analysis
U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 05/31/2016
Version No.:2013.01

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2014

This report is **mandatory** under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning the confidentiality of information in the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly makes to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

PART 1. RESPONDENT IDENTIFICATION DATA

EIA ID NUMBER: 0316008101

If any Respondent Identification Data has changed since the last report, enter an "X" in the box: X

Company Name: Tesoro Refining & Marketing Company LLC
Doing Business As:
Site Name: Anacortes
Terminal Control Number (TCN): T-91-WA-4428

Physical Address (e.g., Street Address, Building Number, Floor, Suite):
10200 W. March Point Rd.
City Anacortes **State:** WA **Zip:** 98221 -

Mailing Address of Contact (e.g., PO Box, RR): If the physical and mailing addresses are the same, only complete the physical address.
19100 Ridgewood Parkway
City San Antonio **State:** TX **Zip:** 78259 -

Contact Name: Laurie Isaac
Phone No.: (210) 626-4224 **Ext:**
Fax No.: (210) 745-4431
Email address: Laurie.A.Isaac@tsocorp.com

PART 2. SUBMISSION/RESUBMISSION INFORMATION

If this is a resubmission, enter an "X" in the box:

A completed form must be received by February 18th of the designated report year.

Forms may be submitted using one of the following methods:

Email: OOG.SURVEYS@eia.gov

Fax: (202) 586-1076

Secure File Transfer: https://signon.eia.doe.gov/upload/noticeoog.jsp

Questions? Call: 202-586-6281

Comments: Explain any unusual or substantially different aspects of your current year's operations that affect the data reported. For example, note new processing units, major modifications or retirement of processing units, sale of refinery, etc. (To separate one comment from another, press ALT+ENTER)

ATTACHMENT 2
O&GJ REFINING SURVEY
JANUARY 1, 2015

2014 Worldwide Refining Survey

Leena Koottungal
Survey Editor/News Writer

All figures in barrels per calendar day (b/cd)

All figures are as of January 1, 2015

LEGEND
Numbers identify processes in table

Coking
1. Fluid coking
2. Delayed coking
3. Other

Thermal process
1. Thermal cracking
2. Visbreaking

Catalytic cracking
1. Fluid
2. Other

Catalytic reforming
1. Semiregenerative
2. Cyclic
3. Continuous regen.
4. Other

Catalytic hydrocracking
1. Distillate upgrading
2. Residual upgrading
3. Lube oil manufacturing
4. Other

c. Conventional (high pressure) hydrocracking: (>100 barg or 1,450 psig)
m. Mild to moderate hydrocracking (<100 barg or 1,450 psig)

Catalytic hydrotreating
1. Pretreatment of cat reformer feeds
2. Other naphtha desulfurization
3. Naphtha aromatics saturation
4. Kerosine/jet desulfurization
5. Diesel desulfurization
6. Distillate aromatics saturation
7. Other distillates
8. Pretreatment of cat cracker feeds
9. Other heavy gas oil hydrotreating
10. Resid hydrotreating
11. Lube oil polishing
12. Post hydrotreating of FCC naphtha
13. Other

Alkylation
1. Sulfuric acid
2. Hydrofluoric acid

Polymerization/Dimerization
1. Polymerization
2. Dimerization

Aromatics
1. BTX
2. Hydrodealkylation
3. Cyclohexane
4. Cumene

Isomerization
1. C_4 feed
2. C_5 feed
3. C_5 and C_6 feed

Oxygenates
1. MTBE
2. ETBE
3. TAME
4. Other

Hydrogen
Production:
1. Steam methane reforming
2. Steam naphtha reforming
3. Partial oxidation
   a. Third-party plant

Recovery:

4. Pressure swing adsorption
5. Cryogenic
6. Membrane
7. Other

NOTES

A Previously listed as Interoil
B Previously listed as Lion Oil Co.
C Previously listed as US Oil & Refining Co.
D Idle
E Previously listed as North Atlantic Refining Ltd.
F New
G Previously listed as Northern Tier Energy LLC
H Previously listed as ERG Raffinerie Mediterranee North
I Previously listed as Shell Refining (Australia) Pty. Ltd.

Capacity definitions:
Capacity expressed in barrels per calendar day (b/cd) is the maximum number of barrels of input that can be processed during a 24-hour period, after making allowances for the following: (a) Types and grades of inputs to be processed, (b) Types and grades of products to be manufactured, (c) Environmental constraints associated with refinery operations, (d) Scheduled downtime such as mechanical problems, repairs, and slowdown. Capacity expressed in barrels per stream day (b/sd) is the amount a unit can process when running at full capacity under optimal feedstock and product slate conditions. An asterisk (*) beside a refinery location indicates that the number has been converted from b/sd to b/cd using the conversion factor 0.95 for crude and vacuum distillation units and 0.9 for all downstream cracking and conversion units.

Hydrogen:

Hydrogen volumes presented here represent either generation or upgrading to 90+% purity.

Catalytic reforming:
1. Semiregenerative reforming is characterized by shutdown of the reforming unit at specified intervals, or at the operators's convenience, for in situ catalyst regeneration.
2. Cyclic regeneration reforming is characterized by continuous or continual regeneration of catalyst in situ in any one of several reactors that can be isolated from and returned to the reforming operation. This is accomplished without changing feed rate or octane.
3. Continuous regeneration reforming is characterized by the continuous addition of this regenerated catalyst to the reactor.
4. "Other" includes nonregenerative reforming (catalyst is replaced by fresh catalyst) and moving-bed catalyst systems.

REFINERY REMOVALS

Name	Location	Country	Crude b/cd	Reason
Caltex Australia Ltd.	Kurnell	Australia	135,000	Converting to fuel import terminal
Flint Hills Resources	North Pole	Alaska	132,050	Costs, contamination
Gulf Atlantic Operations	Alabama	US	20,000	
Italiana Energia E Servizi SPA (c)	Mantova	Italy	69,420	Converting to products logistics hub
LyondellBasell Industries	Berre l'Etang	France	105,000	Converting to terminal
Murco Petroleum Ltd.	Milford Haven	Wales, UK	135,000	Converting to terminal
Pertamina	Pangakalan Brandan, North Sumatra	Indonesia	4,750	

WORLDWIDE REFINING	Charge capacity, b/cd								Production capacity, b/cd									
Company and refinery location	Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
UNITED STATES																		
ALABAMA																		
Hunt Refining Co.—Tuscaloosa	72,000	15,000	[2]32,000	—	—	[1]7,200 [3]16,000	15,000	[1]10,000 [4]2,000 [5]20,000 [8]10,000	—	—	—	—	—	—	a [1]8.0 [4]8.0	500	120	14,000
Shell Chemical Co.—Saraland	79,000	28,000	—	—	—	[1]22,500	[4]30,000	[1]25,000 [9]18,000	—	—	—	[3]7,500	—	—	[6]6.0	—	20	—
Total	151,000	43,000	32,000	—	—	45,700	45,000	85,000	—	—	—	7,500	—	—	22.0	500	140	14,000
ALASKA																		
BP PLC—Prudhoe Bay	15,000	—	[3]15,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ConocoPhillips—Kuparuk	14,500	—	[3]14,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Petro Star Inc.—North Pole	22,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Petro Star Inc.—Valdez	60,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Tesoro Corp.—Kenai	72,000	19,000	—	—	—	[1]12,000	c [1]12,500	[1]12,500	—	—	—	[3]4,000	—	—	a [1]13.0	—	19	1,000
Total	183,500	19,000	29,500	—	—	12,000	12,500	12,500	—	—	—	4,000	—	—	13.0	—	19	1,000
ARKANSAS																		
Cross Oil & Refining Co. Inc.—Smackover	7,000	3,000	—	—	—	—	—	[1]14,500	—	—	—	—	4,500	—	[1]2.5	—	—	1,500
Delek US Holdings Inc.—El Dorado[B]	80,000	64,000	19,000	—	[1]42,000	[3]31,000	—	[1]25,000 [2]23,000 [4]10,000 [5]54,000 [8]50,000	[2]13,500	—	2,200	[3]14,000	—	—	[1]39 [4]22.0	—	285	—
Total	87,000	67,000	19,000	—	42,000	31,000	—	166,500	13,500	—	2,200	14,000	4,500	—	63.5	—	285	1,500
CALIFORNIA																		
Alon USA—Paramount	70,000	59,800	—	—	—	[1]11,600	—	[1]14,500 [4]7,250 [5]13,500	—	—	—	[3]3,750	—	—	—	—	40	35,000
Chevron Corp.—El Segundo	269,000	161,000	[2]67,500	—	[1]65,000	[3]44,000	[1]46,000	[1]41,000 [2]13,000 [4]33,000 [5]36,000 [6]13,000 [8]65,000	[1]30,000	—	—	[1]7,000 [3]20,000	—	—	a [1]69.3	4,064	775	—
Chevron Corp.—Richmond	257,000	110,000	—	—	[1]80,000	[1]69,000	c [1]51,000 c [3]35,000 c [4]65,000	[1]58,000 [4]59,000 [5]30,000	[1]24,000	[1]3,700	—	[1]8,600 [3]28,000	16,000	—	[1]150.0 [4]20.0	—	600	—

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
								[11]30,000										
								[12]20,340										
Phillips 66—Los Angeles (Carson and Wilmington)	138,700	78,000	[2]48,150	—	[1]45,000	[1]34,000	c [1]24,750	[1]50,850	[1]14,400	—	—	[1]8,550	—	—	[1]100.0	2,000	340	—
								[4]11,250				[2]12,500						
								[5]28,800										
								[8]50,000										
Phillips 66—Rodeo and Santa Maria	120,000	87,000	[2]48,000	—	—	[1]31,000	c [1]38,000	[1]29,000	—	—	—	[3]9,000	—	—	[1]130.0	2,500	530	—
							[4]21,000	[5]32,000							[4]3.0			
								[6]15,000										
ExxonMobil Refining & Supply Co.—Torrance	149,500	98,000	[2]50,500	—	[1]83,500	[1]17,000	c [1]21,500	[1]24,000	[2]24,500	—	—	—	—	—	[1]142.0	3,050	380	—
								[7]17,500							[6]9.0			
								[8]102,000										
Kern Oil & Refining Co.—Bakersfield	25,000	—	—	—	—	[1]3,000	—	[1]4,500	—	—	—	—	—	—	—	—	4.5	—
								[3]2,000										
								[5]6,500										
San Joaquin Refining Co. Inc.—Bakersfield	24,300	14,300	—	[2]10,000	—	—	—	[6]3,500	—	—	—	—	4,000	—	[1]4.2	—	6	6,500
								[9]1,800										
Shell Oil Products US—Martinez	145,000	91,100	[2]25,000	—	[1]68,870	[2]29,400	c [1]37,000	[1]27,000	[1]11,000	[2]2,470	—	[3]15,000	—	—	[1]101.0	1,150	360.0	15,000
								[3]19,000										
			[3]21,500															
								[5]22,950										
								[11]9,000										
								[13]40,000										
Tesoro Corp.—Los Angeles	363,000	62,000	[2]40,000	—	[1]36,000	[1]32,500	c [1]32,000	[1]35,750	[1]12,000	—	—	[1]8,000	—	—	a [1]55.0	1,615	265	—
								[3]12,500							[4]55.0			
								[4]15,000										
								[8]38,000										
Tesoro Corp.—Golden Eagle	166,000	144,000	[1]42,000	—	[1]66,500	[1]20,000	c [1]32,000	[1]23,000	[1]14,000	—	—	—	—	—	[1]74.0	1,500	140	—
						[3]22,000		[3]9,000							a [1]31.0			
								[5]32,000										
								[6]14,000										
								[8]62,000										
								[12]27,000										
								[13]5,500										
Valero Energy Corp.—Benicia	170,000	78,500	[1]28,000	—	[1]69,000	[2]36,000	c [1]36,000	[1]29,000	[1]17,100	[2]2,900	—	—	—	—	[1]131.5	1,080	275	5,000
								[3]11,000										
								[4]13,500										

WORLDWIDE REFINING	Charge capacity, b/cd								Production capacity, b/cd									
Company and refinery location	Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
								[8]23,000							[4]46.3 [6]10.9			
Total	**184,500**	**98,800**	**44,500**	**—**	**57,200**	**37,700**	**5,500**	**187,700**	**16,800**	**400**	**—**	**6,800**	**—**	**—**	**161.7**	**1,390**	**290**	**37,300**
NEW JERSEY																		
Phillips 66—Linden	238,000	71,250	—	—	[1]130,500	[2]28,800	—	[1]28,800 [3]6,000 [5]97,200 [12]58,500	[1]16,000	—	—	[1]4,000	—	—	[1]19.8 [6]12.4	—	—	—
PBF Holding Co. LLC—Paulsboro	180,000	90,000	[2]27,000	—	[1]55,000	[3]30,000	—	[1]32,000 [4]27,500 [5]46,000 [11]750 [12]35,000	[2]11,200	—	—	—	11,500	—	[1]13.5 [4]9.0	1,470	230	16,000
Total	**418,000**	**161,250**	**27,000**	**—**	**185,500**	**58,800**	**—**	**331,750**	**27,200**	**—**	**—**	**4,000**	**11,500**	**—**	**54.7**	**1,470**	**230**	**16,000**
NEW MEXICO																		
Western Refining Inc.—Gallup	25,000	—	—	—	[1]7,000	[1]8,000	—	[1]7,500	[2]2,500	—	—	[3]5,000	—	—	—	—	2	—
HollyFrontier Corp.—Artesia	100,000	25,000	—	—	[1]27,000	[3]24,000	—	[7]4,000 [1]35,000 [4]2,400 [5]32,000 [8]28,000	[2]9,000	—	—	[3]11,000	—	—	9.0	—	110	5,000
Total	**125,000**	**25,000**	**—**	**—**	**34,000**	**32,000**	**—**	**108,900**	**11,500**	**—**	**—**	**16,000**	**—**	**—**	**9.0**	**—**	**112**	**5,000**
NORTH DAKOTA																		
Dakota Prairie Refining—Dickinson	20,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Tesoro West Coast Co.—Mandan	71,000	—	—	—	[1]25,700	[2]11,500	—	[1]12,000 [3]11,600	[2]4,200	[1]1,100	—	[3]4,800	—	—	—	—	15	—
Total	**91,000**	**—**	**—**	**—**	**25,700**	**11,500**	**—**	**23,600**	**4,200**	**1,100**	**—**	**4,800**	**—**	**—**	**—**	**—**	**15**	**—**
OHIO																		
BP-Husky*—Toledo	152,000	67,925	[2]31,500	—	[1]49,500	[2]37,800	c [1]27,900	[1]36,000 [5]19,350 [8]42,300	[1]10,350	—	—	—	—	—	—	2,006	351	9,000
Husky Energy Corp.*—Lima	160,000	49,400	[2]20,700	—	[1]36,000	c [2]49,500	[4]23,400	[1]56,700 [12]31,500	—	—	[1]6,300	[3]16,200	—	—	[5]10.4	800	100	—
Marathon Petroleum Co. LP—Canton	90,000	33,300	—	—	[1]24,700	[3]20,400	—	[1]29,000 [4]12,800 [5]20,900 [8]25,700	[2]7,100	—	—	—	—	—	—	—	89	14,100

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
Valero Energy Corp.—Port Arthur	350,000	145,000	[2]100,000	—	[1]80,000	[3]53,000	c [1]60,000 [4]45,000	[12]33,000 [1]52,000 [2]30,000 [4]30,000 [5]55,000 [8]65,000	[2]20,000	—	—	—	—	—	[1]105.0 [4]6.0	6,200	1,050	—
Valero Energy Corp.—Sunray	170,000	53,200	—	—	[1]54,465	[1]18,500 [3]28,900	c [2]29,500	[12]50,000 [1]39,844 [2]22,000 [5]32,368	[1]9,500	—	—	[3]7,000	—	12,200 32,700	—	—	60	—
Valero Energy Corp.—Texas City	250,000	130,000	[1]50,000	—	[2]80,000	[3]14,500	—	[12]3,400 [1]15,000 [4]36,000 [5]52,000 [10]110,000	[2]12,000	—	—	[3]6,500	—	12,500	a [4]60.0	3,000	890	—
Valero Energy Corp.—Three Rivers	100,000	35,000	—	—	[1]24,500	[1]11,000 [3]23,000	—	[12]50,000 [1]23,000 [4]11,000 [5]22,000 [8]20,000	[2]6,500	—	[1]18,000	—	3,200	—	[4]10.0	—	—	—
Western Refining Inc.—El Paso	128,000	34,700	—	—	[1]28,000	[1]18,000	—	[11]2,300 [1]18,300 [4]8,200	[1]10,000	—	—	[1]2,500	—	—	—	—	20	4,800
WRB Refining LLC—Borger	143,000	76,000	[2]27,000	—	[1]50,000	[1]28,000	—	[5]11,300 [1]37,000 [2]24,000 [5]27,000 [7]13,000 [8]70,000	[2]17,000	—	—	[1]16,000 [3]27,000	—	—	[1]83.0 [4]13.0	1,250	340	—
Total	**5,206,600**	**2,231,797**	**868,415**	**—**	**1,695,245**	**1,007,150**	**539,600**	**4,725,842**	**334,960**	**11,200**	**215,819**	**108,600**	**83,750**	**18,500**	**856.3**	**41,308**	**11,724**	**52,467**
UTAH																		
Big West Oil LLC—Salt Lake City	35,000	5,000	—	—	[1]11,500	[3]7,300	—	[1]9,000	[2]2,500	—	—	[1]2,500	—	—	—	—	4	—
Chevron Corp.—Salt Lake City	50,000	25,600	[2]8,100	—	[1]17,800	[1]9,400	—	[5]9,500 [1]7,300 [5]10,200 [7]6,500	[2]4,500	—	—	[3]1,700 [1]1,000	—	—	—	281	56	—

WORLDWIDE REFINING Company and refinery location	Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
		Charge capacity, b/cd							Production capacity, b/cd									
HollyFrontier Corp.—Woods Cross	31,000	—	—	—	[1]8,900	[1]8,000	—	[8]15,000 [1]12,000	[2]2,900	—	—	[3]3,000	—	—	—	—	10	—
Silver Eagle Refining Inc.—Woods Cross	6,250	6,000	—	—	—	[1]2,200	—	[4]3,000 [5]10,000 [5]2,200	—	—	—	—	—	—	—	—	—	1,200
Tesoro West Coast Co.—Salt Lake City	58,000	—	—	—	[1]23,000	[2]12,000	—	4,000 [1]12,000 [5]11,000	[1]6,000	—	—	—	—	—	—	—	15	—
Total	**180,250**	**36,600**	**8,100**	**—**	**61,200**	**38,900**	**—**	**111,700**	**15,900**	**—**	**—**	**8,200**	**—**	**—**	**—**	**281**	**85**	**1,200**
WASHINGTON																		
BP PLC*—Ferndale	222,300	106,400	[2]51,750	—	—	[1]58,500	c [1]58,500	[1]47,700 [2]18,900 [3]20,700 [4]13,500	—	—	—	[3]21,600	—	—	[1]92.5 [4]86.0	3,250	245	—
Phillips 66—Ferndale	101,000	48,200	—	—	[1]32,500	[2]16,600	—	[5]53,460 [1]17,100 [7]29,100 [12]19,900	[2]9,200	—	—	[1]4,100	—	—	—	—	110	—
Shell Oil Products US—Anacortes	145,000	65,500	[2]23,000	—	[1]52,000	[1]33,000	—	[1]33,000	[1]12,050	[1]4,300	—	[2]7,000	—	—	[1]7.0	1,400	350	—
Tesoro West Coast Co.—Anacortes	120,000	47,200	—	—	[1]44,800	[2]26,500	—	[4]15,800 [5]44,400 [12]37,400 [1]36,000	[1]11,000	—	—	[1]3,400	—	—	—	—	48	1,000
TrailStone Group—Tacoma[C]	42,000	17,700	—	—	—	[1]5,650	—	[5]18,500 [8]7,100 [1]8,200 [5]6,600	—	—	—	[3]3,000	—	—	—	—	—	10,000
Total	**630,300**	**285,000**	**74,750**	**—**	**129,300**	**140,250**	**58,500**	**427,360**	**32,250**	**4,300**	**—**	**39,100**	**—**	**—**	**185.5**	**4,650**	**753**	**11,000**
WEST VIRGINIA																		
Ergon-West Virginia Inc.—Newell	23,000	9,700	—	—	—	[1]4,200	—	[1]7,000 [5]9,000 [9]6,600	—	—	—	[3]1,900	5,000	—	[1]4.1	—	1.0	—
Total	**23,000**	**9,700**	**—**	**—**	**—**	**4,200**	**—**	**22,600**	**—**	**—**	**—**	**1,900**	**5,000**	**—**	**4.1**	**—**	**1**	**—**
WISCONSIN																		
Calumet Specialty Products—Superior	45,000	19,500	—	—	[1]9,900	[1]7,200	—	[1]8,100 7,020	[2]1,350	—	—	[3]1,800	—	—	—	—	15	6,750

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
Petroleos de Venezuela SA—Puerto de la Cruz	195,000	—	—	—	[1]13,600	—	—	—	[2]4,100	—	—	—	—	—	—	—	17	—
Petroleos de Venezuela SA—San Roque, Anzoategui	5,200	1,770	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**1,282,100**	**585,780**	**144,900**	**—**	**231,800**	**49,500**	**—**	**389,700**	**65,800**	**—**	**2,000**	**20,700**	**12,020**	**12,830**	**147.8**	**5,200**	**1,471**	**36,000**
VIETNAM																		
Petrovietnam—Dung Quat	140,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**140,000**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
YEMEN																		
Aden Refinery Co.—Little Aden	130,000	10,500	—	—	—	[1]12,000	—	—	—	—	—	—	—	—	—	—	—	3,000
Yemen Oil Co.—Marib	10,000	—	—	—	—	[1]2,500	—	—	—	—	—	—	—	—	—	—	—	—
Total	**140,000**	**10,500**	**—**	**—**	**—**	**14,500**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**3,000**
ZAMBIA																		
Indeni Petroleum Refinery Co. Ltd.—Bwana Nkubwa Area, Ndola	23,750	2,280	—	—	—	[1]5,320	—	[7]8,550	—	—	—	—	—	—	—	—	—	5,527
Total	**23,750**	**2,280**	**—**	**—**	**—**	**5,320**	**—**	**8,550**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**5,527**

APPENDIX C-1.15

ROLLING SUMS AND ROLLING AVERAGES

This Appendix describes how to calculate the standards, exceptions, and triggering events that are on a "Rolling Sum" or "Rolling Average" basis for the flaring requirements in the Consent Decree. Because the calculation of all Rolling Sums and Rolling Averages requires the calculation of Block Sums and Block Averages, respectively, those concepts are described as well. For Rolling Sums, the calculation—as the term "sum" implies—requires the use of addition. For Rolling Averages, the calculation—as the term "average" implies—requires the calculation of the arithmetic mean.

I. ROLLING SUMS

A. Definitions

2.2.1. "Block Sum" means the sum total of the measured or calculated standard, exception, or triggering event during a Block Sum Period. Most often, the term "block sum" is not explicitly used; rather, the concept is implicit in the description.

> *Example 1.a. For an exception to instrument operation that applies during 5% downtime in any six month period, the exception is stated in terms of a "Block Sum"—5% downtime—but it is not explicitly defined as such. The defendant would add together the total number of hours in any six month period that an instrument was not operating and then compare that sum to the allowed Block Sum value to 5% of the total time in the six month period.*

2.2.2. "Block Sum Period" means the uninterrupted period of time during which the Block Sum must be calculated. Most often, the term "Block Sum Period" (and indeed the term "sum period") is not explicitly used; rather, the concept is implicit in the description.

> *Example 1.b. Using Example 1.a, the "Block Sum Period" is a calendar quarter.*

2.2.3. "Rolling Sum" or "*y* rolling sum, rolled *n*" requires: (i) the calculation of a Block Sum during each Block Sum Period of *n* length of time; and (ii) the adding together of the Block Sum values for the total number of Block Sums that equals *y* length of time.

> *Example 2.a. A "365-day rolling sum, rolled daily," requires calculating daily Block Sums and then adding together the values for 365 Block Sums.*

2.2.4. "Rolling Sum Period" means the total length of time for which the Block Sums must be added together.

> *Example 2.b. Using Example 2.a, the "Rolling Sum Period" is 365 Days.*

B. Relationship Between Block Sums and Rolling Sums

2.2.5. The calculation of a Block Sum is implicit or explicit in the calculation of all Rolling Sums.

> *Example 3. A "8760-hour rolling sum" without any further description requires the calculation of an hourly Block Sum and then the adding together of 8760 Block Sums.*

C. Time of Commencement of and Ability to Calculate Block Sums and Rolling Sums

2.2.6. Block Sums. A Block Sum commences with the first value that is recorded at the start of each Block Sum Period. A Block Sum cannot be calculated until after the last value in the Block Sum Period is recorded.

> *Example 4. For a Block Sum Period that is "daily," the calculation of the Block Sum commences with the value that is recorded starting at midnight each calendar day and ends with value that is recorded immediately prior to midnight of the next Day. For a Block Sum Period that is "hourly," the calculation of the Block Sum commences with the value that is recorded at the top of each hour and ends with value that is recorded immediately prior to the start of the next hour.*

2.2.7. Rolling Sums. A Rolling Sum commences with the first Block Sum that is calculated. A Rolling Sum cannot be calculated until the last Block Sum of the Rolling Sum Period is calculated.

> *Example 5. For a 365-day Rolling Sum, rolled daily, the Rolling Sum commences with the Block Sum that is calculated on the first Day of the Rolling Sum Period; however, the first Rolling Sum cannot be calculated until the first 365 Days are over (i.e., the 365-day Rolling Sum Period is completed).*

D. Standards, Exceptions and/or Triggering Events in this Consent Decree that Are on a "Rolling Sum" Basis

2.2.8. The following standards, exceptions, and/or triggering events are on a "rolling sum" basis in the Consent Decree. These standards, exceptions, and/or triggering events therefore require the calculation of Block Sums during Block Sum Periods in order to calculate Rolling Sums:

TABLE 1

Generic Description of Standards, Exceptions, and/or Triggering Events	Actual Standard, Exception, and/or Triggering Event in the CD	**Block Sum Period** (the "rolled by" period)	**Rolling Sum Period**
Percentage of Time Anacortes, Martinez 50U, Martinez 19/DCU, Mandan, Salt Lake City, Kapolei, and Kenai Compressors Are Available for Operation and/or In Operation	**95% of the time** (2 Compressors); **98% of the time** (1 Compressor) (¶¶ 131.b.i and 131.b.ii)	Hourly	8760 hours
Hours a Portable Flare is In Operation during outage(s) of a Covered Flare	**504 hours** (¶¶ 143.c and d)	Daily	1095 days

E. <u>Calculating Rolling Sums for the Percentage of Time a Compressor is Available for Operation and/or In Operation</u>

2.2.9. <u>Calculate each Hourly Block Sum</u>. Calculate the amount of time that a compressor is Available for Operation and/or In Operation ("A") during each hour (*i.e.*, during each Block Sum Period). Calculate the amount of time during each hour (*i.e.*, each Block Sum Period) that the standard is applicable and for which an exemption does not apply ("R"). Calculate each hourly Block Sum as A/R (which will be a percentage of time). If an exclusion applies during the entire hour, then that hour is not included in the Rolling Sum calculation.

2.2.10. <u>Calculate the Rolling Sum for the First Rolling Sum Period</u>. Add together the first 8760 hourly Block Sums. Use only the prior 8760 1-hour periods when at least some part of the hour was not covered by an exclusion.

2.2.11. <u>Continue Calculating the Rolling Sum</u>. Drop out the first Block Sum (*i.e.*, the first hour) in the first Rolling Sum Period and add in the 8761^{st} Block Sum.

F. <u>Calculating Rolling Sums for Exempted Hours of Maintenance on FGRS</u>

2.2.12. <u>Calculate each Daily Block Sum</u>. Calculate the amount of time that a particular Compressor is shut down for exempted maintenance during each Day (*i.e.* during each Block Sum Period).

2.2.13. <u>Calculate the Rolling Sum for the First Rolling Sum Period</u>. Add together the first 1826 daily Block Sums ((5 years x 365 Days) + 1 leap year Day).

2.2.14. <u>Continue Calculating the Rolling Sum</u>. Drop out the first Block Sum (*i.e.*, the first Day) in the first Rolling Sum Period and add in the 1827th Block Sum.

G. <u>Calculating Rolling Sums for the Number of Hours a Portable Flare Is In Operation During the Outage of a Covered Flare</u>

2.2.15. <u>Calculate each Daily Block Sum</u>. Calculate the number of hours that the Portable Flare is In Operation during each Day (*i.e.* during each Block Sum Period).

2.2.16. <u>Calculate the Rolling Sum for the First Rolling Sum Period</u>. Add together the first 1095 daily Block Sums.

2.2.17. <u>Continue Calculating the Rolling Sum</u>. Drop out the first Block Sum (*i.e.*, the first Day) in the first Rolling Sum Period and add in the 1096th Block Sum.

II. <u>ROLLING AVERAGES</u>

A. <u>Definitions</u>

2.2.18. "Block Average" means the arithmetic mean of a measured or calculated parameter during a Block Average Period.

> *<u>Example 6.a</u>. For an exit velocity standard that is applicable on a one-hour Block Average, the arithmetic mean of all of the measurements during a one-hour period is calculated and compared to the standard.*

2.2.19. "Block Average Period" or "Block Period" means the uninterrupted period of time during which the Block Average must be calculated.

> *<u>Example 6.b</u>. Using Example 6.a, the "Block Average Period" is one-hour.*

2.2.20. "Rolling Average" or "*y* rolling average, rolled *n*" requires: (i) the calculation of a Block Average during each Block Average Period of *n* length of time; and (ii) the calculation of the arithmetic mean of the Block Average values for the total number of Block Averages that equals *y* length of time.

<u>Example 7.a</u>. A "3-hour rolling average, rolling every 15 minutes" requires the calculation of 15-minute Block Averages and then the calculation of the arithmetic mean of 12 (i.e., 3 x 4) 15-minute Block Averages.

2.2.21. "Rolling Average Period" means the total length of time for which the arithmetic mean of the Block Averages must be calculated.

<u>Example 7.b</u>. Using Example 7.a, the "Rolling Average Period" is 3 hours.

B. <u>Relationship Between Block Averages and Rolling Averages</u>

2.2.22. The calculation of a Block Average is implicit or explicit in the calculation of all Rolling Averages.

<u>Example 8</u>. A "365-day rolling average" without any further description requires the calculation of daily Block Averages. A "1-hour rolling average, rolled every 5 minutes," requires the calculation of 5-minute Block Averages.

C. <u>Time of Commencement of and Ability to Calculate Block Averages and Rolling Averages</u>

2.2.23. <u>Block Averages and Rolling Averages</u>. The description set forth in Paragraphs 2.2.6 and 2.2.7 for time of commencement of and ability to calculate Block Sums and Rolling Sums applies equally to Block Averages and Rolling Averages.

<u>Example 9</u>. For "a 3-hour rolling average, rolled every 15 minutes," the calculation of the Block Average commences with the first value that is recorded starting at the top of each 15 minute period and ends with the last value that is recorded immediately prior to the start of the next 15 minute period. The Rolling Average commences with the first 15-minute Block Average that is calculated but the first Rolling Average cannot be calculated until all the first twelve Block Averages are calculated. ("Twelve" is the appropriate number of prior 15-minute Block Averages because there are four 15-minute Block Averages in one hour; therefore, there are twelve 15-minute Block Averages in three hours (4 x 3). The "3-hour rolling average, rolled every 15 minutes" would equal the arithmetic mean of twelve 15-minute Block Averages.)

D. <u>Parameters in this Consent Decree that are on a "Rolling Average" Basis</u>

1.2.24. The following parameters are on a "rolling average" basis in this Consent Decree. These parameters therefore require the calculation of Block Averages during Block Average Periods in order to calculate Rolling Averages:

TABLE 2

Generic Description of the Parameter	Standard in the CD	Block Average Period (the "rolled by" period)	Rolling Average Period
Waste Gas volumetric flow rate	30-day and 365-day limits	Daily	30 Days and 365 Days

E. When Measured values are "Zero" in a Block Average Period

2.2.25. If, during a Block Average Period, a parameter is measured to be zero, the number "0" is used for that measurement when determining the arithmetic mean of the values (*i.e.*, the Block Average) during the Block Average Period. If all of the measured values during a Block Average Period are zeros, the Block Average is the number "0." "0" *is* a value and "0" should be used in calculating the arithmetic mean. This is distinct from the circumstances identified in Paragraphs 2.2.26 and 2.2.27 below.

F. When One or More Measured Values Either May Be Excluded for Some Part of a Block Average Period and/or Do(es) Not Exist for Some Part of a Block Average Period.

2.2.26. If, for any reason, one or more value(s) of a parameter either: (i) may be excluded for some part of a Block Average Period and/or (ii) do(es) not exist for some part of a Block Average Period (*e.g.*, an instrument is down), only the remaining value(s) in the Block Average Period are to be used in measuring or calculating the Block Average. For clarity, values that are excluded or do not exist are ***not*** given the number "0." They should not have any value assigned to them. The Block Average is the arithmetic mean of the non-excluded, existing values.

G. When All Values in a Block Average Period May Be Excluded and/or Do(es) Not Exist.

2.2.27. If, for any reason, the value(s) of a parameter either: (i) may be excluded during the entirety of a Block Average Period; and/or (ii) do(es) not exist for the entirety of a Block Average Period (*e.g.*, an instrument is down), then there is ***no*** Block Average for that Block Average Period. (For clarity, the number "0" is *not* the Block Average value in this circumstance.) Under this circumstance, there will be a gap in the Block Average Periods that have values (sometimes referred to as a "gap in the data").

III. WHEN COMPLIANCE FIRST CAN BE DEMONSTRATED

2.2.29. For both Rolling Sums and Rolling Averages, compliance cannot be demonstrated until the first Rolling Sum Period or Rolling Average Period is completed.

> *Example 11. For a standard that is applicable on a 365-day rolling average, rolled daily, where the initial compliance date is January 1, 2014, values must start to be recorded at midnight on January 1, 2014. The first daily Block Average that can be calculated is at midnight on January 2, 2014. Then, assuming there are no gaps in the data, the first Rolling Average that can be calculated is at midnight on January 1, 2015. The first Rolling Average would be the arithmetic mean of the 365 Block Averages calculated for January 1, 2014, through December 31, 2014.*

APPENDIX C-2.1

	A	B	D	E	F	G	H	I	J	K	L
1	**Appendix 2.1 - Covered Flares and Applicability Dates for Certain Consent Decree Requirements**										
2	**CD Paragraph No.**	**CD Requirement (N/A = Requirement Does Not Apply)**	**Kenai - Refinery Flare (AA)**	**Kapolei - Refinery Flare**	**ANR - Vertical Flare (X-813)**	**ANR - Horizontal Flare (X-814) (GF)**	**SLC - North flare**	**SLC - South flare**	**MAN - Alky flare**	**MAN - GHT flare**	**MAN - Combo flare**
3		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	AA	SA	SA	SA	SA	SA	SA	SA	SA
4	113.a	Complete installation of visual image of S/VG ratio	N/A	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015
5	113.b	Complete Training on Steam Control	N/A	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015
6	113.c	Operate Covered Flares to minimize *S/VG* ratio to extent practicable	N/A	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015
7	114	Evaluate Meters Measuring Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
8	115	Minimize Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
9	116	Minimize Leaking PRVs	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
10	117	Install Vent Gas, Steam Assist, and Air Assist Flow Monitoring System	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
11	118	Install Vent Gas Composition Monitoring System	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
12	119	Install Video Camera	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
13	127	Initial Flare Management Plan	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
14	128	Updated Flare Management Plan	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018

	A	B	D	E	F	G	H	I	J	K	L
15	CD Paragraph No.	CD Requirement (N/A = Requirement Does Not Apply)	Kenai - Refinery Flare (AA)	Kapolei - Refinery Flare	ANR - Vertical Flare (X-813)	ANR - Horizontal Flare (X-814) (GF)	SLC - North flare	SLC - South flare	MAN - Alky flare	MAN - GHT flare	MAN - Combo flare
16		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	AA	SA	SA	SA	SA	SA	SA	SA	SA
17	130	Flare Gas Recovery System Start-Up	10/1/2016	7/1/2017	6/1/2016	6/1/2016	2/1/2016	2/1/2016	N/A	7/1/2016	7/1/2016
18	132	Limitations On Flaring - Begin collecting data for compliance	4/1/2017	1/1/2018	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
19	132	Limitations On Flaring - 30-Day Limit Compliance	5/1/2017	1/31/2018	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017
20	132	Limitations On Flaring - 365-Day Limit Compliance	4/1/2018	1/1/2019	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018
21	135.a and 135.f.	Emission Standards and Work Practices - Operation During Waste Gas Venting, Good Air Pollution Control Practices	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
22	135.b and 136.c	Visible Emissions, Flame Presence	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019
23	135.d	Flare Tip Velocity	N/A	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017
24	137	Automate Supplemental Gas Flow Rate	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
25	138	Operation According to Design	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
26	139	Net Heating Value Standards for NHVcz (combustion zone)	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017
27	140	96.5% Combustion Efficiency	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017
28	142	Recordkeeping	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017
29	144	Air Assisted Flare Requirements - Instrumentation and Monitoring Systems	10/1/2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
30	145	Dilution Operating Limits for Flares with Perimeter Assist Air	10/1/2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	146	Kenai Passive PFTIR Testing	11/29/2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	151	NSPS Subparts A and Ja Applicability	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015

	A	B	D	E	F	G	H	I	J	K	L
33	**CD Paragraph No.A50**	**CD Requirement (N/A = Requirement Does Not Apply)**	**Martinez - Unit 50 flare**	**Martinez - DCU flare**	**Martinez - East Air flare**	**Martinez - West Air flare**	**Martinez - Emergency flare**	**Martinez - North Steam flare**	**Martinez - South Steam flare**	**Martinez - Tank 691 flare**	
34		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	SA	SA	AA	AA	UA	SA	SA	SA	
35	113.a	Complete installation of visual image of S/VG ratio	NA	10/1/2015	N/A	N/A	N/A	10/1/2015	10/1/2015	N/A	
36	113.b	Complete Training on Steam Control	NA	12/1/2015	N/A	N/A	N/A	12/1/2015	12/1/2015	N/A	
37	113.c	Operate Covered Flares to minimize *S/VG* ratio to extent practicable	NA	12/1/2015	N/A	N/A	N/A	12/1/2015	12/1/2015	N/A	
38	114	Evaluate Meters Measuring Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
39	115	Minimize Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
40	116	Minimize Leaking PRVs	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
41	117	Install Vent Gas, Steam Assist, and Air Assist Flow Monitoring System	NA	4/1/2017	1/30/2019	1/30/2019	N/A	4/1/2017	4/1/2017	N/A	
42	118	Install Vent Gas Composition Monitoring System	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	4/1/2017	4/1/2017	N/A	
43	119	Install Video Camera	N/A	N/A	N/A	N/A	N/A	4/1/2017	4/1/2017	N/A	
44	127	Initial Flare Management Plan	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	
45	128	Updated Flare Management Plan	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	

	A	B	D	E	F	G	H	I	J	K	L
46	**CD Paragraph No.**	**CD Requirement (N/A = Requirement Does Not Apply)**	**Martinez - Unit 50 flare**	**Martinez - DCU flare**	**Martinez - East Air flare**	**Martinez - West Air flare**	**Martinez - Emergency flare**	**Martinez - North Steam flare**	**Martinez - South Steam flare**	**Martinez - Tank 691 flare**	
47		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	SA	SA	AA	AA	UA	SA	SA	SA	
48	130	Flare Gas Recovery System Start-Up	4/1/2015	4/1/2015	4/1/2015	4/1/2015	4/1/2015	4/1/2015	4/1/2015	N/A	
49	132	Limitations On Flaring - Begin collecting data for compliance	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	
50	132	Limitations On Flaring - 30-Day Limit Compliance	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	
51	132	Limitations On Flaring - 365-Day Limit Compliance	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	
52	135.a and 135.f	Emission Standards and Work Practices - Operation During Waste Gas Venting, Good Air Pollution Control Practices	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
53	135.b and 135.c	Visible Emissions, Flame Presence	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	
54	135.d	Flare Tip Velocity	NA	7/1/2017	1/30/2019	1/30/2019	N/A	7/1/2017	7/1/2017	N/A	
55	137	Automate Supplemental Gas Flow Rate	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	4/1/2017	4/1/2017	N/A	
56	138	Operation According to Design	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
57	139	Net Heating Value Standards for NHVcz (combustion zone)	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	10/1/2017	10/1/2017	N/A	
58	140	96.5% Combustion Efficiency	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	10/1/2017	10/1/2017	N/A	
59	142	Recordkeeping	10/1/2017	1/30/2019	1/30/2019	1/30/2019	10/1/2017	10/1/2017	10/1/2017	10/1/2017	
60	144	Air Assisted Flare Requirements - Instrumentation and Monitoring Systems	N/A	N/A	1/30/2019	1/30/2019	N/A	N/A	N/A	N/A	
61	145	Dilution Operating Limits for Flares with Perimeter Assist Air	N/A	N/A	1/30/2019	1/30/2019	N/A	N/A	N/A	N/A	
62	146	Kenai Passive PFTIR Testing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
63	151	NSPS Subparts A and Ja Applicability	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	Has Not Been Triggered	

APPENDIX C-2.2

Appendix C-2.2
Large, High Pressure Relief Valves

Refinery	Process Unit	Relief Valve Description	Inlet / Outlet Size, inches	Pressure Set Point, psig
ANA	Alky	PSV-0942	4x6	310
ANA	Bensat	PSV-6716	4x6	730
ANA	Bensat	PSV-6714	3x4	630
ANA	Butamer	PSV-0775	4x6	350
ANA	CFH	PSV-1012-1	3x4	960
ANA	CFH	PSV-7180-1	3x4	350
ANA	CR	PSV-6684-1	3x4	775
ANA	DHT	PSV-7109	3x4	850
ANA	DHT	PSV-6809	3x4	750
ANA	NHT	PSV-6601-1	3x4	585
ANA	NHT	PSV-6688-1	3x4	550
ANA	NHT	PSV-6651	4x6	330
ANA	ROSE	PSV-5513	4x6	787
ANA	ROSE	PSV-5514	4x6	787
ANA	ROSE	PSV-5502	3x4	750
ANA	ROSE	PSV-5503	3x4	750
ANA	Treaters	PSV-5000	4x6	323
KAP	ATU	14-PSV-107	3x4	440
KAP	ATU	PSV-1306	3x4	325
KAP	ATU	PSV-A109	3x4	325
KAP	ATU	PSV-1305	3x4	324
KAP	ATU	PSV-1308	3x4	323
KAP	ATU	PSV-1307	3x4	320
KAP	CRU	PSV-R570	3x4	330
KAP	CRU	14-PSV-424	3x4	319
KAP	DHC	PSV-H13-1	3x6	1810
KAP	DHC	PSV-H13-2	3x6	1810
KAP	VDU	PSV-V3	4x6	500
KEN	Crude	PSV-1703	4x6	350
KEN	Crude	PSV-1704	4x6	350
KEN	Crude	PSV-1705	4x6	350
KEN	Crude	PSV-1710	3x4	425
KEN	DHC	PSE-4802	4x6	325
KEN	DHC	PSV-4068	4x6	385
KEN	DHC	PSV-4802	4x6	325
KEN	H2	PSV-10604	3x6	435
KEN	H2	PSV-10607	4x6	315

Appendix C-2.2

Large, High Pressure Relief Valves

Refinery	Process Unit	Relief Valve Description	Inlet / Outlet Size, inches	Pressure Set Point, psig
KEN	PRIP	PSV-12606	3x4	340
KEN	PRIP	PSV-12609	3x4	340
KEN	Vacuum	PSV-17400	3x4	310
MAN	ALKY	PSV-A-011 T-1 Deprop	4x6	330
MAN	ALKY	PSV-A-011S T-1 Deprop	4x6	330
MAN	GHT	PSV-G-101 C-75S Comp. Discharge	3x4	331
MAN	GHT	PSV-G-107 PSA Feed KO D-97	3x4	340
MAN	ULTRA	PSV-500 D-101 Desulfurizer	4x6	319
MAN	ULTRA	PSV-904 F-200 Furnace	3x4	447
MAN	ULTRA	PSV-905 F-200 Furnance	3x4	450
MAN	ULTRA	PSV-926 F-200 Reactor Charge	3x4	455
MAN	ULTRA	PSV-961 E-3A Shell Side	4x6	461
MTZ	1 HDA	A010PSV0025	3x4	750
MTZ	1 HDS	A005PSV0189	4x6	631
MTZ	2 HDS	A004PSV0009	4x6	720
MTZ	2 HDS	A004PSV0098	4x6	720
MTZ	2 HDS	A004PSV0088	3x4	1000
MTZ	2 HDS	A004PSV0093	3x4	980
MTZ	3 Crude	A048PSV0047	4x6	343
MTZ	3 Crude	A048PSV1047	4x6	361
MTZ	3 HDS	A076PSV1007	3x4	500
MTZ	3 HDS	A076PSV1538	6x8	525
MTZ	3 HDS	A076PSV1539	6x8	525
MTZ	3 HDS	A076PSV1021	3x4	1925
MTZ	3 HDS	A076PSV1022	3x4	1935
MTZ	3 HDS	A076PSV1023	3x4	1985
MTZ	3 HDS	A076PSV1024	3x4	2015
MTZ	3 HDS	A076PSV1026	4x6	481
MTZ	3 HDS	A076PSV1132	4x6	505
MTZ	3 HDS	A076PSV1133	3x4	675
MTZ	4 HDS	A092PSV0007	4x6	340
MTZ	5 Gas	A003PSV0036	4x6	360
MTZ	5 Gas	A003PSV0002	4x6	320
MTZ	5 Gas	A003PSV0003	4x6	320
MTZ	50 Crude	A016PSV0077	4x6	350
MTZ	Ben Sat	A091PSV0004	4x6	450
MTZ	Ben Sat	A091PSV0005	4x6	330

Appendix C-2.2

Large, High Pressure Relief Valves

Refinery	Process Unit	Relief Valve Description	Inlet / Outlet Size, inches	Pressure Set Point, psig
MTZ	Ben Sat	A091PSV0015	4x6	300
MTZ	DHC Stg 2	A068PSV0017	4x6	424
MTZ	DHC Stg 2	A068PSV0037	3x4	1590
MTZ	DHC Stg 2	A068PSV0091	6x10	305
MTZ	DHC Stg 2	A068PSV0071	3x4	460
MTZ	DHC Stg 2	A068PSV0021	6x8	450
MTZ	DHC Stg 1	A067PSV0014	3x6	1780
MTZ	DHC Stg 1	A067PSV0024	4x6	400
MTZ	DHC Stg 1	A067PSV0615	6x8	420
MTZ	DHC Stg 1	A067PSV0020	6x8	450
MTZ	DHC Stg 1	A067PSV0016	6x8	450
MTZ	DHC Stg 2	A068PSV0036	3x4	1590
MTZ	DHC Stg 2	A068PSV0092	6x10	310
MTZ	DHC Stg 2	A068PSV0080	6x8	450
MTZ	H2	A069PSV0011	3x4	461
MTZ	Reformate Frac	A006PSV0040	3x4	750
MTZ	Reformate Frac	A006PSV0033	4x6	480
SLC	Alky	F-446 Caustic Drum	3x4	335
SLC	Alky	F-447 Water Wash Drum	3x4	325
SLC	BSU	R-501 - BSU Rx	3x5	570
SLC	DDU	D-621 High Pressure Separator	3x4	1360
SLC	UFU	F-1A/B/C/D Feed Preheat Furnace	4x6	330
SLC	UFU	E-77 Reactor EFF/ DESULF Feed	4x6	320
SLC	VRU	C-116	3x4	600

APPENDIX
C-2.3

COMBUSTION EFFICENCY TEST DESCRIPTION FOR KENAI AIR ASSISTED FLARE

1.0 Introduction

This appendix describes the approach for conducting a combustion efficiency performance test on the main refinery Flare at the Kenai Refinery. This Flare is air-assisted. More specific information describing how the testing will be performed will be included in the test protocol required to be submitted for agency approval per Paragraph 146 of the Consent Decree.

2.0 Test Objective and Boundary Conditions

Tesoro will conduct a combustion efficiency performance test on the air-assisted main refinery Flare at the Kenai Refinery. The primary objective of the Flare's performance test is to measure combustion efficiency over a range of Flare operating conditions.

While the Flare operating conditions will be purposefully varied between test runs, each individual test run will be conducted under stable conditions as defined by the approved test protocol. Meteorological conditions will be monitored to ensure that test runs are conducted under conditions that ensure the presence of a consistent plume cross-section during each test run.

3.0 Flare Performance Test Description

A Passive Fourier Transform Infrared (PFTIR) instrument will be used to measure combustion efficiency of the Flare. The testing will be conducted during weather conditions conducive to this testing technology.

During the testing, the Vent Gas composition, calorific value, and flow rate will be required to remain relatively stable and the Assist-Air rate will be varied to provide a performance curve of optimal stoichiometric air ratio ($\dot{m}_{air\text{-asst}}/\dot{m}_{air\text{-}stoich\text{-}vg}$). Each operating scenario necessary to establish a stoichiometric air ratio to measured combustion efficiency is defined as a "test run." During each test run, the PFTIR analyzer will remotely analyze the combustion gases in the Flare plume to determine combustion efficiency. The result will be a defined Flare operating envelope as a function of Combustion Zone Gas Net Heating Value bounded by the incipient smoke point on one side and over-assisting on the other. The testing will not include evaluating combustion efficiency on plumes having visible emissions.

The anticipated total time for the test (data acquisition time only) is about 12 to 16 hours or more depending on the number of Assist Air flow conditions to be tested and atmospheric conditions. The duration of each test run will be approximately 15 minutes and will be synchronized to the gas chromatograph ("GC") analysis cycle.

The following compounds in Table 1 will be measured in the GC:

Table 1

Compound	Mol. Wt.	Range	Units
Hydrogen	2.02	0 - 100	mole %
Nitrogen	28.01	0 - 100	mole %
Oxygen	32.00	0 - 100	mole %
Carbon Dioxide	44.01	0 - 100	mole %
Carbon Monoxide	28.01	0 - 100	mole %
Methane	16.04	0 - 100	mole %
Ethane	30.07	0 - 100	mole %
Ethylene	28.05	0 - 100	mole %
Propane	44.10	0 - 100	mole %
Propylene	42.08	0 - 100	mole %
Iso-Butane	58.12	0 - 100	mole %
Butane	58.12	0 - 100	mole %
Butenes + 1,3 Butadiene	54.09	0 - 100	mole %
Pentane-Plus (C5+)	72.15	0 - 100	mole %
Hydrogen Sulfide	34.08	0 - 100	Mole %

During the testing the Flare gas may vary significantly in both flow and composition. During the test the Flare gas flow rates will be measured continuously with the existing ultrasonic flow monitor. The Assist Air rate will be monitored by supply-air fan curve calculations or flow meter. Determination of molecular weight of the Flare gas will also be provided for every test run via the GC. This data should allow operators to hold a steady $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ ratio even as flow rates and composition varies.

Both thermal and visual video recordings will be collected and stored. A timestamp for each image will saved with the video so the video can be referenced to each test run.
One aiming camera mounted to the PFTIR will record the point at which the PFTIR is pointed. One high definition visual color camera will be beside the PFTIR to record the overall Flare flame and plume. One infrared camera will be beside each PFTIR to record the thermal image of the Flare plume.

The following additional elements of the testing approach will be presented in the test protocol:

- Expected location of the PFTIR relative to Flare location
- Data collection approaches
- PFTIR operation and calibration details
- Thermal and video camera operation and calibration details

4.0 Data Collection

Process data will be provided by plant operations and include process data, Vent Gas composition data, and meteorological data. Table 2 lists the parameters and time interval that will be recorded and delivered by plant operations. The GC) used for measuring Flare gas composition will report the compounds listed in Table 1.

Table 2

Parameter	Unit	Frequency
Flare Gas Volumetric Flow	scfh	1 minute
Flare Gas Mass Flow Rate	lb/hr	1 minute
Flare Gas Molecular Weight	lb/lb-mole	1 minute
Flare Gas Composition	vol. %	15 minutes
Estimated Pilot Gas Flow Rate	lb/hr	N/A
Assist Air Mass Flow Rate	lb/hr	1 minute
Assist Air Temperature at Flow Measurement Point	°F	1 minute
Flare Gas Combustion Zone Net Heating Value	BTU/scf	15 minutes
Vent Gas Net Heating Value	BTU/scf	15 minutes
Actual Total Assist Air to Vent Gas Ratio	--	1 minute
Hydrocarbon Mass Flow Rate	lb/hr	15 minutes
Flare Exit Velocity	fps	1 minute
Wind Direction	°	1 minute
Wind Speed	mph	1 minute
Ambient Barometric Pressure	in. Hg	1 minute
Ambient Temperature	°F	1 minute
Ambient Humidity	%	1 minute

APPENDIX C-2.4

APPENDIX 2.4

Refinery	Calculation Basis	Refinery Crude Capacity (b/cd)	Refinery Complexity[2]	US Complexity[2]	Refinery/US Complexity	30-Day Rolling Average SCFD	365-Day Rolling Average SCFD
Anacortes	EIA/O&GJ (b/cd)[1]	120,000	8.24	11.19	0.736	662,670	441,780
Kapolei	EIA/O&GJ (b/cd)[1]	93,500	4.69	11.19	0.419	293,681	195,787
Kenai	EIA/O&GJ (b/cd)[1]	65,000	5.31	11.19	0.475	231,354	154,236
Mandan	EIA/O&GJ (b/cd)[1]	70,000	6.68	11.19	0.596	313,139	208,759
Martinez	EIA/O&GJ (b/cd)[1]	166,000	13.63	11.19	1.218	1,516,353	1,010,902
Salt Lake	EIA/O&GJ (b/cd)[1]	57,500	7.05	11.19	0.630	271,505	181,003

Notes:

1) Data in barrels per calendar day (b/cd) are shown on the next page.

2) Nelson Complexity factors are shown on the next page, and are specified in Appendix C-1.14

Anacortes Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1)	US Capacity (b/cd, except H2 and S)	Source (Note 1)
Atmospheric Distillation	1	120,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	44,650	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	50,700	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Fe	6	2,700	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	23,400	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8		Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	88,200	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	12,420	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000		Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	49	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreakin	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	3,240	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5	4,950	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**8.24**		**11.19**	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/25/2014 and available at www.eia.gov) were used preferentially, see Attachment 1, along with the corresponding Tesoro capacities as of 1/1/2014 submitted by Tesoro on Form EIA-820 Annual Refinery Report Parts 5, 6 and 7, see Attachment 2. For processes where US capacities were not included on the US EIA report (i.e. Polymerization and Oxygenates), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2013) calendar day capacities as of 1/1/2014 were used for both the US and Tesoro, see Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

Kapolei Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1) for Prior	US Capacity (b/cd, except H2 and S)	Source (Note 1)	EPA Capacity (b/cd, except H2 and S)	EPA Source (Note 1)	EPA US Capacity (b/cd, except H2 and S)	EPA Source (Note 1)
Atmospheric Distillation	1	93,500	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd	93,500	EIA 2014 Data, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	38,000	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95	38,000	EIA 2014 Data, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5	0	There is no coker at the Kaoplei Refinery.Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd	0	There is no coker at the Kaoplei Refinery.	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	0	There is no FCC at the Kapolei Refinery. Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd	0	There is no FCC at the Kapolei Refinery.	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	0	There is no FCC at the Kapolei Refinery. Part 6, Tesoro's 2014 EIA-820, b/cd	68,301	EIA Website 2014 Data, b/sd*0.9	0	There is no FCC at the Kapolei Refinery.	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	12,500	Part 5, Tesoro's 2014 EIA-820, b/cd. The capacity on a stream day basis is listed as 13,000 BPD and calendar basis as 12,500	3,419,407	EIA Website 2014 Data, b/cd	12,500	EIA 2014 Data, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8	19,000	Part 5, 2014 EIA-820, b/cd includes 17500 gas oil and 1500 distillate	2,034,689	EIA Website 2014 Data, b/cd	19,000	EIA 2014 Data, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	12,500	Naphtha/Refomer Feed Hydrotreating was listed 13,000 BSD on EIA. Set barrels per calendar to aligned with 12,500 BCD specified for Reformer as set forth in the EIA report	15,385,086	EIA Website 2014 Data, b/sd*0.9	11,700	EIA 2014 Data, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	0	There is no Alkylate Unit at the Kapolei refinery.	1,164,521	O&GJ (12/5/2013), b/cd	0	There is no alky at the Kapolei Refinery.	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000	18	The capacity of the H2 plant is 18 MMSCF/D. Tesoro's EIA -820	4,104	O&GJ (12/5/2013), b/cd	16	EIA 2014 Data, b/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	38	The Kapolei refinery has 2 SRUs which are described on the Title V permit as 14 and 20 LTPD (total 24 LTPD) or approximately 38 short tons per day and this is consistent with EIA-820. The O&GJ (12/5/2013),incorrectly lists zero(0) t/cd .	32,693	O&GJ (12/5/2013), b/cd	34	EIA 2014 Data, b/sd*0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75	9,900	Part 6, Tesoro's 2013 EIA-820, 11,000 b/sd	16,000	EIA Website 2014 Data, b/sd*0.9	9,900	EIA 2014 Data, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10	0	There is no Polymerization Unit at the Kapolei Refinery. The O&GJ (12/5/2013),incorrectly lists 1,000 b/cd	71,870	O&GJ (12/5/2013), b/cd	0	There is no poly at the Kapolei Refinery.	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20	0	O&GJ (12/5/2013), b/cd	366,869	O&GJ (12/5/2013), b/cd	0	There is no aromatics at the Kapolei Refiner	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	0	There is no isomeration unit at the Kapolie refinery. The O&GJ (12/5/2013),incorrectly listed 1200 b/cd	661,815	O&GJ (12/5/2013), b/cd	0	There is no isom at the Kapolei Refinery.	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10	0	O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd	0	There is no oxygenates at the Kapolei Refin	32,250	O&GJ (12/5/2013), b/cd
Lubes	60	0	O&GJ (12/5/2013), b/cd	193,300	O&GJ (12/5/2013), b/cd	0	There is no lubes at the Kapolei Refinery.	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5	0	Although the Kapolei refinery previously operated an air blown asphalt plant, that method of producing asphalt was suspended in 2006. The O&GJ (12/5/2013), incorrectly lists 1,300 b/cd	486,117	O&GJ (12/5/2013), b/cd	0	There is no asphalt at the Kapolei Refinery.	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		4.74		11.23869157		4.69		11.19	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries"

Kenai Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1)	US Capacity (b/cd, except H2 and S)	Source (Note 1)
Atmospheric Distillation	1	65,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	24,700	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6		Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	10,500	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8	12,000	Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	22,050	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000	12	Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	24	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	4,500	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5	9,000	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**5.31**		**11.19**	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/25/2014 and available at www.eia.gov) were used preferentially, see Attachment 1, along with the corresponding Tesoro capacities as of 1/1/2014 submitted by Tesoro on Form EIA-820 Annual Refinery Report Parts 5, 6 and 7, see Attachment 2. For processes where US capacities were not included on the US EIA report (i.e. Polymerization and Oxygenates), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2013) calendar day capacities as of 1/1/2014 were used for both the US and Tesoro, see Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

Mandan Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1)	US Capacity (b/cd, except H2 and S)	Source (Note 1)
Atmospheric Distillation	1	70,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3		Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	26,460	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	3,240	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	12,000	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8		Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	36,180	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	3,960	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000		Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	15	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10	1,100	O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	4,800	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**6.68**		**11.19**	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/25/2014 and available at www.eia.gov) were used preferentially, see Attachment 1, along with the corresponding Tesoro capacities as of 1/1/2014 submitted by Tesoro on Form EIA-820 Annual Refinery Report Parts 5, 6 and 7, see Attachment 2. For processes where US capacities were not included on the US EIA report (i.e. Polymerization and Oxygenates), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2013) calendar day capacities as of 1/1/2014 were used for both the US and Tesoro, see Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

Martinez Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1)	US Capacity (b/cd, except H2 and S)	Source (Note 1)
Atmospheric Distillation	1	166,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	149,055	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5	50,000	Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	70,000	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	900	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	22,900	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8	35,900	Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	178,200	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	13,860	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000	74	Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	180	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**13.63**		**11.19**	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/25/2014 and available at www.eia.gov) were used preferentially, <u>see</u> Attachment 1, along with the corresponding Tesoro capacities as of 1/1/2014 submitted by Tesoro on Form EIA-820 Annual Refinery Report Parts 5, 6 and 7, <u>see</u> Attachment 2. For processes where US capacities were not included on the US EIA report (i.e. Polymerization and Oxygenates), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2013) calendar day capacities as of 1/1/2014 were used for both the US and Tesoro, <u>see</u> Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

Salt Lake City Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1)	US Capacity (b/cd, except H2 and S)	Source (Note 1)
Atmospheric Distillation	1	57,500	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3		Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	22,400	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	2,700	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	11,100	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8		Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	31,320	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	5,940	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000		Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	16	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**7.05**		**11.19**	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/25/2014 and available at www.eia.gov) were used preferentially, see Attachment 1, along with the corresponding Tesoro capacities as of 1/1/2014 submitted by Tesoro on Form EIA-820 Annual Refinery Report Parts 5, 6 and 7, see Attachment 2. For processes where US capacities were not included on the US EIA report (i.e. Polymerization and Oxygenates), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2013) calendar day capacities as of 1/1/2014 were used for both the US and Tesoro, see Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

APPENDIX C-2.5

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